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ONE STRATEGIC MOVE AFTER ANOTHER

UPTON RESOURCES INC.

2000 ANNUAL REPORT

UPTON
CORE AREAS

SOUTHEAST SASKATCHEWAN

At 4,246 barrels per day, Upton operates a significant base of production in southeast Saskatchewan. 94% of production and 83% of reserves represent the majority of cash flow and net asset value for the Company.

Upton's plans for southeast Saskatchewan are to continue its excellent exploration and development record highlighted by 2000 discoveries at Melrose and Harthaven and increasing Midale production to 1,200 barrels per day. An asset sale of non-core properties in Q1 2001 yielded premium prices and Upton reduced debt with the $7.2 million in proceeds.

NORTHERN U.S.

Production reached 414 barrels per day by year-end. At Tracy Mountain/Davis Creek, on the strength of 6 wells drilled in 2000, this two-zone play added a new pool discovery in the Tyler zone that will require more drilling to define its size and 2 million barrels of long-life reserves in the Fryburg zone.

In 2001, Upton plans to exploit a sizable drilling inventory adding production and reserves so this core area grows in significance.

NORTHWEST ALBERTA

Commodity and geological diversification began in 2000 with an entry into a natural gas play. With additional acquisitions in Q1 2001 land holdings increased substantially. Production and reserves will be modest in 2001 but Upton can build on its position in the 2001/2002 winter drilling season.

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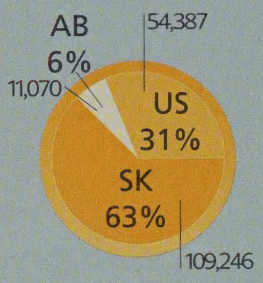
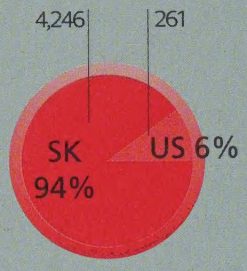
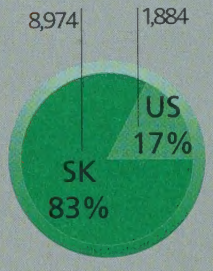
LAND
(174,703 net acres)

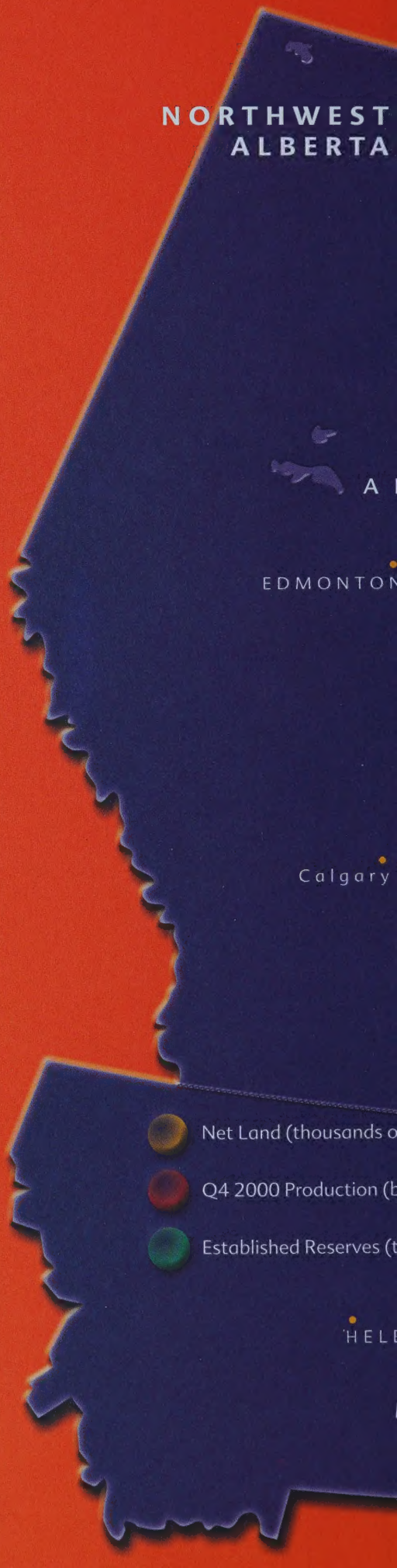


Q4 2000 PRODUCTION
(4,507 barrels per day)



ESTABLISHED RESERVES
(10,858 M barrels)

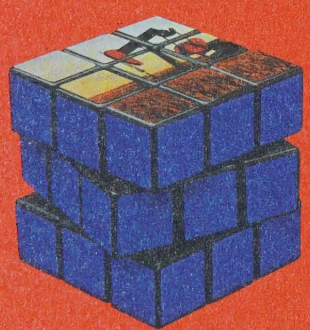




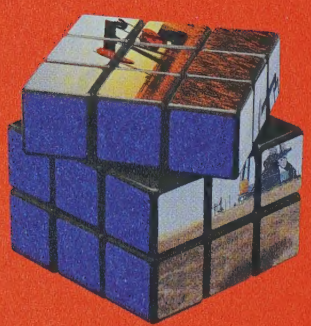
RTA
SASKATCHEWAN
MANITOBA
Saskatoon
REGINA
WINNIPEG
4,246
8,974
109,246
SOUTHEAST
SASKATCHEWAN
er day)
d barrels)
NORTH
DAKOTA
261
1,884
54,387
BISMARCK
NORTHERN U.S.
NTANA

YEAR 2000 WAS A MAJOR TURNING POINT FOR UPTON RESOURCES.

THE COMPANY GENERATED RECORD NET EARNINGS AND CASH FLOW AND BEGAN TO CHANGE ITS ASSET MIX. THE KEY MOVES WERE THESE.



STRENGTHENED ITS BASE CASH FLOW IN SOUTHEAST SASKATCHEWAN.

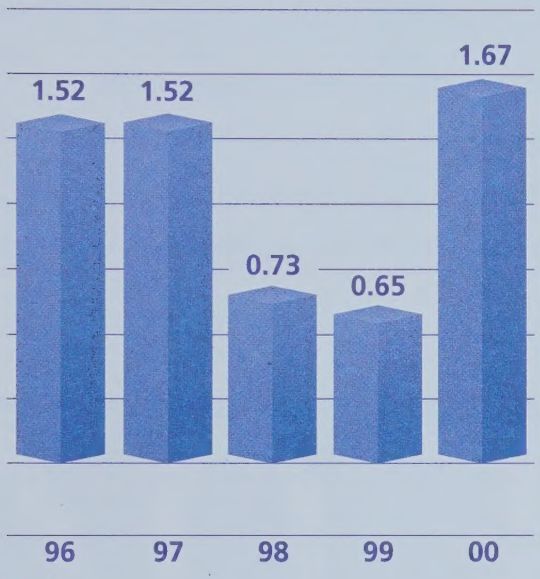


PROVED UP THE TRACY MOUNTAIN/ DAVIS CREEK OIL CONCEPT.

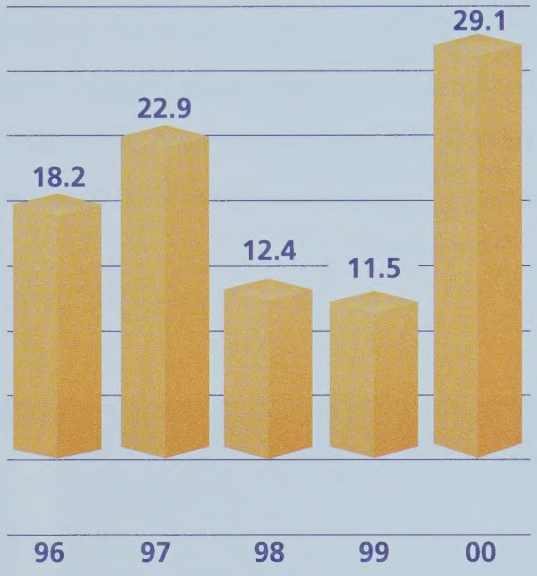
SECURED NATURAL GAS POSITION IN NORTHWEST ALBERTA.

CORPORATE HIGHLIGHTS

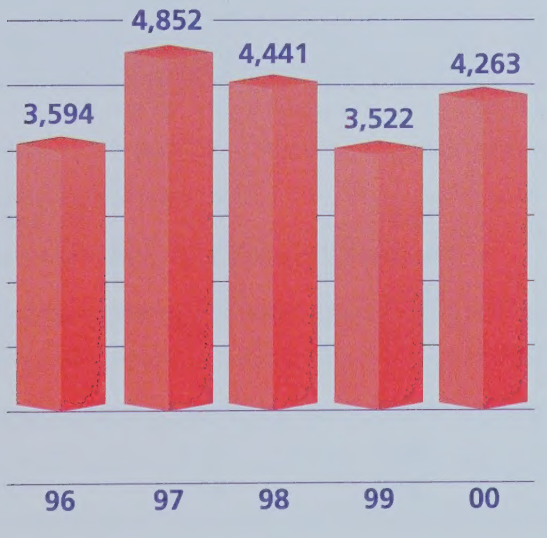
Cash Flow per Share ($ per share)



Cash Flow from Operations ($ MM)



Production (barrels per day)



Net Asset Value per Share (PV 10%)

FINANCIAL HIGHLIGHTS

$000s except per share amounts	2000	1999	% Change
Revenue	**56,616**	31,139	82
Cash flow from operations	**29,100**	11,490	153
per share	**1.67**	0.65	157
Net earnings	**10,925**	1,411	674
per share	**0.63**	0.08	688
Long-term debt including working capital	**30,119**	28,316	6
Shareholders' equity	**38,275**	28,661	34
Net asset value (PV 10%)	**87,446**	58,412	50
per share	**5.09**	3.29	55
Oil price realized	**36.28**	24.22	50

OPERATING HIGHLIGHTS

	2000	1999	% Change
Production (barrels per day)	**4,263**	3,522	21
Established reserves (thousands of barrels)	**10,858**	10,931	(1)
Total net land (thousands of acres)	**175**	189	(7)
Wells drilled			
Gross	**46.0**	24.0	92
Net	**35.6**	22.0	62
Operating costs ($ per barrel)	**3.80**	4.22	(10)

PRESIDENT'S MESSAGE

Two-thousand was a strong year for Upton. The Company's technical team conducted a substantial exploration and development drilling program that saw average production increase 21 percent over 1999 to 4,263 barrels per day. The production increase, Upton's continued focus on operating costs and a favourable crude oil price, drove record levels of cash flow and net earnings. Upton's strengthened operating and financial position allowed the Company's management team to undertake strategic moves that we believe will have a significant positive impact on Upton's future.

During 2000 and the first months of 2001, Upton:

- **Achieved a strong drilling and production performance in southeast Saskatchewan, the Company's main cash flow-generating area.** In 2000, Upton drilled 38 (32.3 net) wells, increased production, and made exploration discoveries at Melrose and Harthaven. In March, 2001, Upton sold non-core producing properties for $7.2 million.
- **Proved our exploration and development concept at Tracy Mountain/Davis Creek, North Dakota.** Upton is seeking larger, longer-life, light oil reserves, and drilling to date has exceeded our expectations for the potential of this play. Our first-year development drilling program at Tracy Mountain/Davis Creek brought production to 316 barrels per day net by year-end. Potential reserves exceed 6 million barrels. Tracy Mountain/Davis Creek has proven itself to be Upton's second Core Area;
- **Attained a significant working interest at low cost in a large expanse of natural gas-prone lands in northwest Alberta.** This play's potential for productive, medium-depth natural gas pools, for a company Upton's size, is significant. Upton's operating partner is a highly successful natural gas producer. Drilling commenced in December 2000, and to date Upton has participated in 7 new gas pool discoveries. The play, named Larne/Bistcho, is becoming Upton's third Core Area.

These moves had three strategic objectives:

- **Maintain a strong production base.** An active drilling program on internally generated prospects generates strong cash flow and maintains Upton's primary focus on creating value through the drill bit;
- **Increase financial flexibility**. Proceeds from asset dispositions reduce long-term debt and improve financial flexibility through greater debt capacity that can be used to exploit emerging opportunities; and
- **Diversification.** Extensive, long-life light oil reserves at Tracy Mountain/Davis Creek will strengthen Upton's overall reserve life, while the addition of natural gas production helps balance commodity risk and diversify Upton's geographic focus beyond the oily Williston Basin.

SCOTT DUTTON — *PRESIDENT AND CHIEF EXECUTIVE OFFICER*

GREG HENDERS — *VICE PRESIDENT OPERATIONS*

PHIL GRUBBE — *VICE PRESIDENT FINANCE AND CHIEF FINANCIAL OFFICER*

ANDY ST. ONGE — *VICE PRESIDENT EXPLORATION*

ROBIN IRWIN — *VICE PRESIDENT LAND*

The first objective is clearly being accomplished. The second objective has also been accomplished, and given the premium price of the March asset sale, Upton is evaluating further divestments. The third is well underway — in one year, Upton has diversified from one core area into three, without losing a step.

2000 PROGRAM

Upton entered 2000 with growing cash flow and dozens of drilling locations in our prospect inventory. Our strengthened position allowed Upton to conduct a $29.5 million exploration and development program. Our first priority was further development of our Midale property and exploration in southeast Saskatchewan resulting in new discoveries at Harthaven and Melrose. Our initial well at Davis Creek, North Dakota was brought on production in January. Its excellent performance combined with our improving cash flow allowed us to add $5 million to our original capital budget to enhance development of Davis Creek and explore at Tracy Mountain.

The drilling program of 46 wells yielded 36 oil wells, 3 disposal wells and 7 dry holes, for an overall success rate of 84 percent. 2000 was a great year for exploration success. This included new pool discoveries at Melrose and Harthaven in southeast Saskatchewan and new production from two separate zones at Tracy Mountain/Davis Creek in North Dakota. Initial proven producing reserve additions are modest but both zones have excellent low risk potential. Our development program also achieved great results. Development drilling at Tracy Mountain/Davis Creek increased production to 316 barrels per day net at year-end. In southeast Saskatchewan, Upton increased production at Midale to 1,200 barrels per day. We hit our overall target exit rate of 5,000 barrels per day in early December. December average production of 4,933 barrels per day provided a strong entry point for 2001.

Commodity prices worked to our advantage last year, remaining significantly higher throughout the year. Although this was offset somewhat by our hedged production, Upton generated an average sales price of CDN$36.28 per barrel. We continued to focus on remaining a low-cost operator and achieved an average operating cost of $3.80 per barrel of production in 2000, among the lowest in the Canadian oil industry. This boosted Upton's all-in cash netback to more than $20 per barrel in the fourth quarter.

The financial results were tremendous. Upton generated cash flow of $29.1 million in 2000, an increase of 153 percent over 1999. We repurchased and cancelled 600,175 shares through a normal course issuer bid. These two factors combined to move cash flow per share to $1.67, an increase of 157 percent over 1999. Net earnings increased to $10.9 million in 2000 from $1.4 million in 1999, a year-over-year gain of 674 percent. Net earnings per share rose by 688 percent over 1999, reaching $0.63 in 2000. Cash flow and net earnings are both Company historical highs.

These excellent results created, for the first time in several years, the financial flexibility needed for Upton to begin repositioning itself for the longer term. I would like to discuss three strategic moves in some detail, because they are key to understanding Upton's plan to create value.

SOUTHEAST SASKATCHEWAN

At Upton, we see ourselves primarily as growing through the drill bit, and we have built up a strong track-record of success at cost-effectively finding and developing new reserves. Upton's basic strategy has been to find new pools and add production from the light oil deposits that exist in southeast Saskatchewan. Upton has spent years accumulating a thorough technical understanding of the shallow, Paleozoic-age carbonate reservoirs of the Williston Basin. Our business model here is to attain small but key land positions at high working interests on prospects we have identified, and then to lead exploration and development programs as operator. This tight focus has enabled us to generate very high drilling success rates, maintain low operating costs and maximize returns to Upton.

In 2000, Upton focused on developing our Midale property, now our largest producing property. We drilled 11 (11 net) wells and increased production to average 963 barrels per day, an increase of 119 percent over 1999. Midale holds total proven reserves of 1.5 million barrels and we have a two-year inventory of drillable locations for an additional 1.2 million barrels before development is completed.

During the year we achieved exploration success at Melrose and Harthaven, where we made new discoveries. Two Upton wells at Melrose achieved production of 407 barrels per day at year-end, and we have identified a further 7 drilling locations. At Harthaven, a 100 percent Upton step-out well achieved production of more than 291 barrels per day at year-end. The pool extension we have confirmed will allow drilling of 4 development wells in 2001.

Upton will continue to explore for and develop new pools in southeast Saskatchewan. Many of our properties offer significant upside potential. Several others, developed over the past 10-15 years, are maturing and last year we recognized they represent opportunity to generate cash that can be re-deployed to self-finance exploration and development at more promising projects.

An agreement for the sale of non-core properties in southeast Saskatchewan was reached in February 2001. The sale unlocked significant value held in the ground. The proceeds of $7.2 million cash represent $30,600 per daily producing barrel, a strong premium to Upton's stock market trading value of about $18,000 per daily producing barrel.

The proceeds were used to pay down a portion of Upton's debt. Although debt represented only one times 2000 cash flow, we felt it was an excellent time to strengthen our financial flexibility by increasing available credit. Our purchase and participation in an active natural gas exploration program shows that financial flexibility is crucial to participating in emerging opportunities. Initial results suggest that Upton will replace the sale volumes with a fraction of the sale proceeds.

TRACY MOUNTAIN/DAVIS CREEK, NORTH DAKOTA

Upton has been mindful of the potential benefits of eventually branching out into a prospect area offering larger, longer life reserves. Tracy Mountain/Davis Creek, North Dakota is such an area. Upton had been working on the foundations for this play since 1996 — assembling land, obtaining working interests, conducting seismic evaluations, forging partnerships and meeting environmental concerns. At Tracy Mountain we first focused on the Tyler Sands. By 1998, we had also come to believe that the adjoining Davis Creek area held extensive reserves in the medium-depth Mississippian Fryburg zone. Both zones are deeper than geologically similar pools in southeast Saskatchewan, and the Fryburg zone in particular offers long-life, large reserve potential of 300,000-900,000 barrels per well, three to nine times the reserves of a typical well in southeast Saskatchewan.

In January 2000, Upton launched the development of Tracy Mountain/Davis Creek, drilling a total of 6 (2.1 net) exploratory and development wells, including a new pool discovery in the Tyler sand. This drilling program generated production of 939 barrels per day (316 net) at year-end. Upton has booked over 2 million barrels of reserves, with additional reserve potential in both zones of several million barrels of oil. We are very excited by these results. Upton has 7,996 net acres of undeveloped land, and we have identified 25-30 additional drill sites. Upton's drilling program in 2001 will begin to evaluate three similar plays in the area at working interest of 80-100 percent. In 2001, we will drill a further 9 wells at this Core Area, and over a three-year period we estimate production can be increased to 1,200-1,500 barrels per day net to Upton.

NORTHWEST ALBERTA

In December 2000 and February 2001, Upton secured a substantial position in natural gas after evaluating numerous plays in the past few years. Several factors made our search a challenge, principally the escalating cost of natural gas properties and the limited upside of many shallow gas prospects. Late last year Upton identified a promising opportunity which began with a six section farm-in of land held by a private operator in the Larne/Bistcho area in northwest Alberta. This prospect soon developed into a major entry point into natural gas for Upton, after discussions were initiated with a major U.S. producer that was preparing to exit a large acreage position in the area.

Upton through purchase and farm-in, acquired an average 25 percent interest in 268 sections of land and natural gas production of 220,000 cubic feet per day. Acquisition and drilling costs of up to 15 wells are expected to total $5.0 million in the first quarter of 2001. Upton's operating partner, a natural gas producer experienced in winter drilling operations, has constructed pipeline and gas plant infrastructure in the area with capacity currently available.

Exploration licenses on all but 46 sections of the acquired lands are due to expire, so an active winter drilling program was launched. The strong success of the initial drilling encouraged the partners to expand to a 15-well program, sufficient to retain more than half the expiring acreage. Upton's share of production will be communicated to shareholders as drilling results are known and tie-ins accomplished prior to the end of the winter drilling season. Current plans include the tie-in of 5 to 7 wells in April 2001.

By assembling a largely undeveloped play with low current production but a large land base, Upton was able to enter the natural gas sector in the cost-effective manner we had sought. The Larne/Bistcho area lies northeast of Zama just south of the Alberta-Northwest Territories boundary. The Slave Point and Sulphur Point reservoirs lie at approximately 1,500 metres, and successful wells typically produce at 1 to 10 million cubic feet (160-1,600 barrels of oil equivalent at 6:1) per day. The prospective lands generally support an average of one well for every two sections of land. Upton's interest area in turn is adjoined by dozens of sections of unexplored Crown lands. The medium to long term opportunities in this region are excellent.

RESERVES AND NET ASSET VALUES

Upton's exploration success added millions of barrels of reserves to our asset base in 1998, primarily with the booking of more than 4 million barrels of reserves at Midale in southeast Saskatchewan. Although Upton continued to conduct exploration drilling and discover new reserves, our primary focus through 1999 and 2000 was developing our recently discovered reserves. Consequently, total reserves have remained largely flat during the past three years. However, Upton's mix of reserves is changing, with more than 2 million barrels, or 17 percent of total reserves, represented by long-life reserves at Davis Creek.

During 2000, Upton added 1.4 million barrels at Davis Creek and 800,000 barrels at Melrose and Harthaven. In southeast Saskatchewan, Upton decided to reduce a portion of less valuable probable reserves previously booked. The reduction totalled 850,000 barrels, representing 6.6 percent of Upton's total reserves base. While this decision raised our finding and development costs for 2000, Upton's three-year average remains an excellent $7.60 per barrel for established reserves.

The strengthening of commodity prices in 1999 and 2000 and the movement of reserves to the producing category through drilling has provided significant improvement to Upton's net asset values. At year-end 2000, Upton's present value for established reserves at PV 10 percent totalled $114 million. Our net asset value totalled $87.4 million at PV 10 percent and reached $5.09 per share. This compared to $58.4 million and $3.29 per share in 1999, a year-over-year increase in per share net asset value of 55 percent. Natural gas reserves at Larne/Bistcho are not included in this total and have already added to Upton's net asset value in 2001.

THE YEAR AHEAD

Our strong financial results in 2000, our short-term development plans and the long-term promise of our strategic moves leave me very excited about Upton's prospects for 2001 and beyond. This year our energies will be directed at closing the gap between Upton's share price and its net asset value, and our priorities will be to:

- Continue to develop our strong base of producing properties and recent exploration successes in southeast Saskatchewan, while pursuing new exploration targets, with a view to maintaining a strong base of high potential properties from this Core Area;
- Increase drilling at Tracy Mountain/Davis Creek, designed to add more long-life reserves and more than double our U.S. production;
- Drill one or two exciting high working interest North Dakota Fryburg exploration plays;
- Continue to market mature producing properties at prices that are accretive to Upton's shareholders;
- Conduct an intensive technical study and 3D seismic program at Larne with a view to assembling a multi-year inventory of drilling prospects. Following the promising results of the first quarter of 2001, we intend to follow with an active drilling program in the 2001-2002 winter drilling season, including acting as operator on several wells;
- Use a portion of our cash to purchase and cancel shares through our normal course issuer bid; and
- Use our strong financial position to seek further opportunities to participate cost-effectively in new natural gas or crude oil plays within and outside our historical core operating area.

We currently have at least two years' worth of drilling locations in our inventory of prospects. Upton will carry out a capital program totalling $32.8 million in 2001, of which more than $14 million will be dedicated to exploration. The drilling plan calls for 49 (27.3 net) wells, with emphasis on Larne/Bistcho where 16 wells are planned, 9 wells at Tracy Mountain/Davis Creek, 8 wells at Midale and 8 wells at Harthaven and Melrose. We are targeting unrisked average production of 4,500 barrels of oil equivalent per day in 2001, which will be year-over-year growth of 5 percent as we focus increasingly on exploration. The natural gas production target in the Larne/Bistcho play is modest, at 750 thousand cubic feet per day average for the year. Upton is targeting cash flow of $30 million ($1.75 per share) and net earnings of $8.0 million ($0.47 per share) in 2001.

Upton began 2000 optimistic about our chances for significant success. The year exceeded our expectations. Upton's team worked very hard through 2000, and can take great satisfaction in what we accomplished. My thanks go to them, to our Board of Directors and to you for your continued support for the Upton plan. Entering the third month of 2001 we have the strongest confidence in Upton's prospects for success.

On behalf of the Board of Directors,

G. Scott Dutton
President and Chief Executive Officer
March 7, 2001

EXPLORATION AND OPERATIONS REVIEW

Upton is a major explorer and producer of light crude oil in the Williston Basin. An exploration and development drilling program totalling 35.6 net wells brought the Company's average production to 4,263 barrels per day in 2000. This was an increase of 21 percent over 1999. At $3.80 per barrel, Upton in 2000 incurred among the lowest operating costs per barrel of production in the Canadian industry.

OPERATING STRATEGY

Last year Upton used its growing cash flow from increased production volumes and netbacks to its maximum advantage, conducting strategic moves in three key areas that were aimed at maximizing future upside potential, diversifying commodity mix and helping to maintain the Company's primary focus on adding value through drilling.

These were:

- Exploration and development drilling at the Company's southeast Saskatchewan Williston Basin properties, which furnish the majority of Upton's production and cash flow. Strong cash flow from growing volumes and a continued focus on low operating costs funded the Company's expansion into new play areas. Growing financial strength was complemented by disposition of a non-core producing property in March, 2001 for $7.2 million;

- Expansion in the North Dakota portion of the Williston Basin, which offers larger, longer-life reserve potential. Following Upton's initial success at Davis Creek in the Fryburg zone, successful drilling at the Upton-operated properties increased production through the year to 939 barrels per day (316 net) from 6 consecutive successful wells, one of which was a new pool discovery in the Tyler zone; and
- Acquiring a significant land position in a natural gas-prone play area in the Larne/Bistcho area of northwest Alberta. Exploratory drilling on this extensive land base which will cover up to 268 sections (171,840 gross acres) of undeveloped land, began in early 2001 and a major drilling program is ongoing for this winter season.

UPTON HOLDS REGULAR STRATEGIC PLANNING MEETINGS WHERE EMPLOYEES CONTRIBUTE TO THE FUTURE DIRECTION OF THE COMPANY

LAND

Upton's Williston Basin land strategy is prospect-driven. The Company acquires prospective parcels highlighted by geological or seismic mapping in areas where additional land capture is possible following exploration success. Upton seeks operatorship and high working interests in new lands in order to control the pace of expenditure and to leverage its technical expertise in the Williston basin. This strategy changed with Upton's entry into natural gas exploration where Upton will be an active partner working with an experienced winter drilling operator.

During 2000, Upton spent $2.6 million in land expenditures. A total of 27,161 net acres were acquired. Average prices per acre were $59 in Saskatchewan and $149 in the U.S., in line with area norms. Undeveloped acreage in northwest Alberta totalled 11,070 net acres at year-end at an average cost of $7 per acre, as Upton took the first steps toward a major position in natural gas-prone lands. Undeveloped acreage in southeast Saskatchewan decreased by 25,784 acres as a result of a number of expiries and modest acquisitions. In the U.S., new prospects in the vicinity of Tracy Mountain/Davis Creek were obtained with the acquisition of 7,295 (6,251 net) acres.

The major part of our northwest Alberta land acquisition occurred in the first quarter of 2001. In a series of transactions, Upton acquired working interests ranging from 3.125 percent to 50 percent in 268 sections (171,840 acres) of mainly undeveloped land. Approximately 60 percent of these lands were held under four-year exploration license and are due to expire following the 2000-2001 winter drilling season. An active drilling program was launched in December 2000, and as of mid-March, 2001 Upton expects in excess of half the land base would be held under long-term leases.

Upton's total land base at year-end 2000 was 194,266 (150,548 net) undeveloped acres. Developed acres stood at 31,999 (24,155 net).

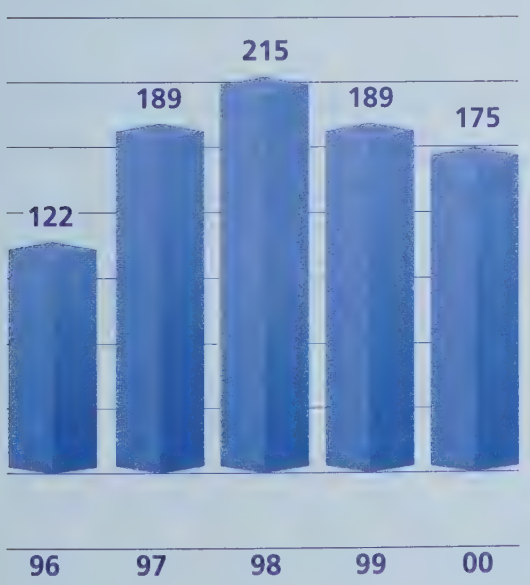
2000 TOTAL LAND HOLDINGS

Acres	Gross	Net	WI%
Developed	31,999	24,155	75.49
Undeveloped	194,266	150,548	77.50
Total	226,265	174,703	77.21

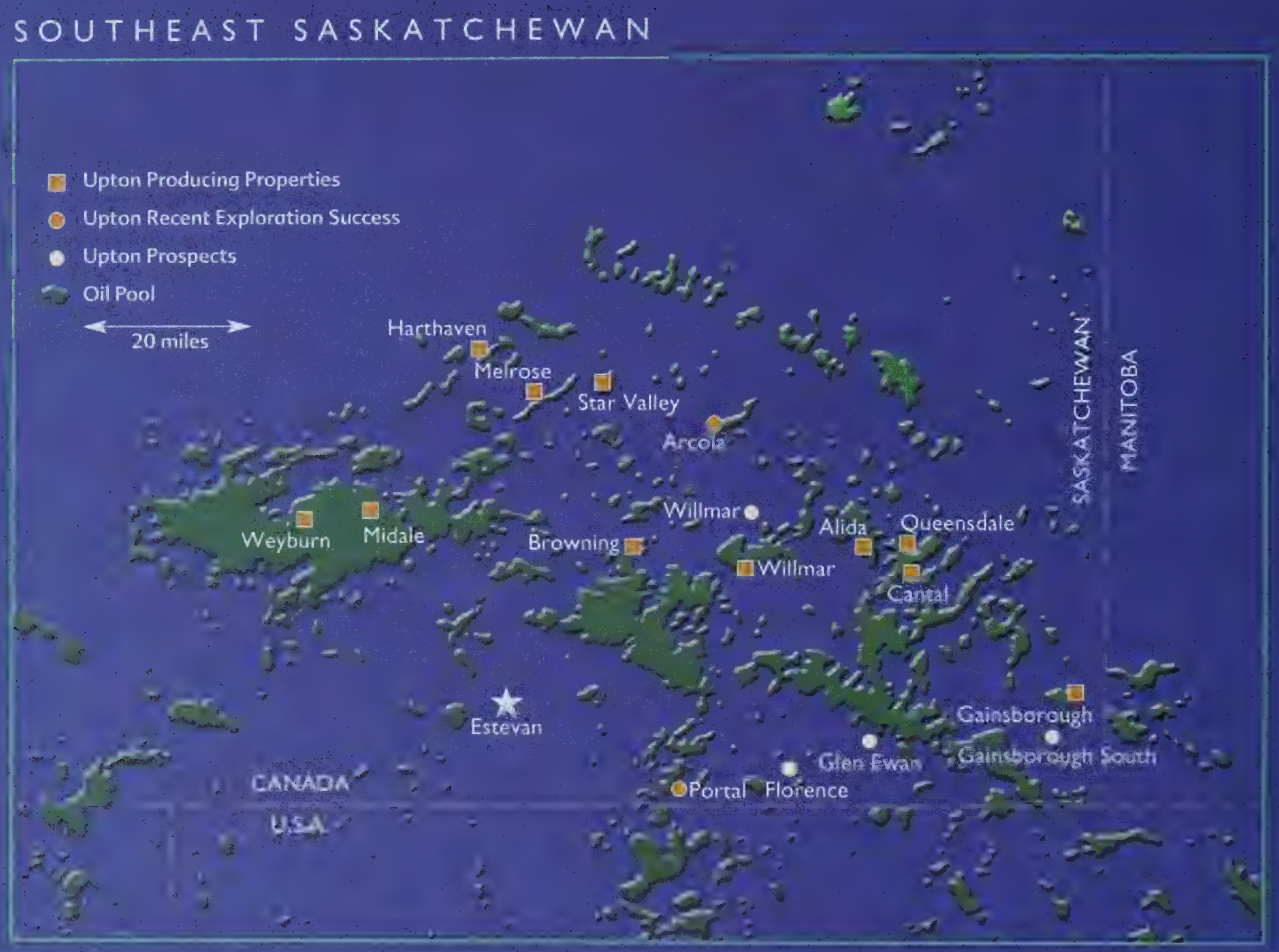
UNDEVELOPED LAND RECONCILIATION

Acres	Gross	Net
Undeveloped land January 1, 2000	222,050	166,130
Acquisitions	62,468	27,161
Expires and reallocations	88,252	42,743
Undeveloped land December 31, 2000	194,266	150,548

NET LAND HOLDINGS (000 ACRES)



OPERATING COSTS ($/BARREL)



REVIEW OF CORE AREAS

SOUTHEAST SASKATCHEWAN

Upton had a successful year in its primary core area of southeast Saskatchewan. Through an active oil exploration and development program totalling 38 (32.3 net) wells, production increased by 19 percent from 1999 to a 2000 average of 4,067 barrels per day. This represented 95 percent of Upton's total production.

The basis of Upton's historical success is its thorough technical understanding of the shallow, Paleozoic-age, light-oil-producing carbonate reservoirs prevalent in the Williston Basin. Although the Basin has been explored for more than 50 years, there is still significant potential in exploring for smaller fields and pool extensions using offset well information together with modern, high-quality 3D seismic data.

Through careful prospecting, Upton has made several significant discoveries in the last decade, including those at Melrose and Harthaven in 2000. Once a field has been delineated by vertical wells and tied to 3D seismic, development by horizontal wells can proceed with confidence. By penetrating along the porosity trend rather than simply drilling through it, horizontal wellbores access twice the reserves and average three times the productivity of a vertical well. Upton's proven business model achieves higher-volume production, improved recoveries and reduced risk, along with rapid pay-out, and high return on capital.

Upton's primary producing properties in southeast Saskatchewan are Midale, Gainsborough, Browning, Star Valley, Queensdale, Alida, and Cantal. At year-end Upton produced more than 558 barrels per day from exploration prospects at Melrose and Harthaven and will develop these further in 2001.

Upton drilled a total of 4 (2.6 net) horizontal development wells at Alida, Cantal and Queensdale in 2000, bringing combined production to an average of 1,067 barrels per day in 2000, an increase of 36 percent over 1999. At year-end 2000, booked reserves totalled 1.8 million barrels at the three properties. In 2001 the Company will drill 3 horizontal wells at Queensdale to maintain production.

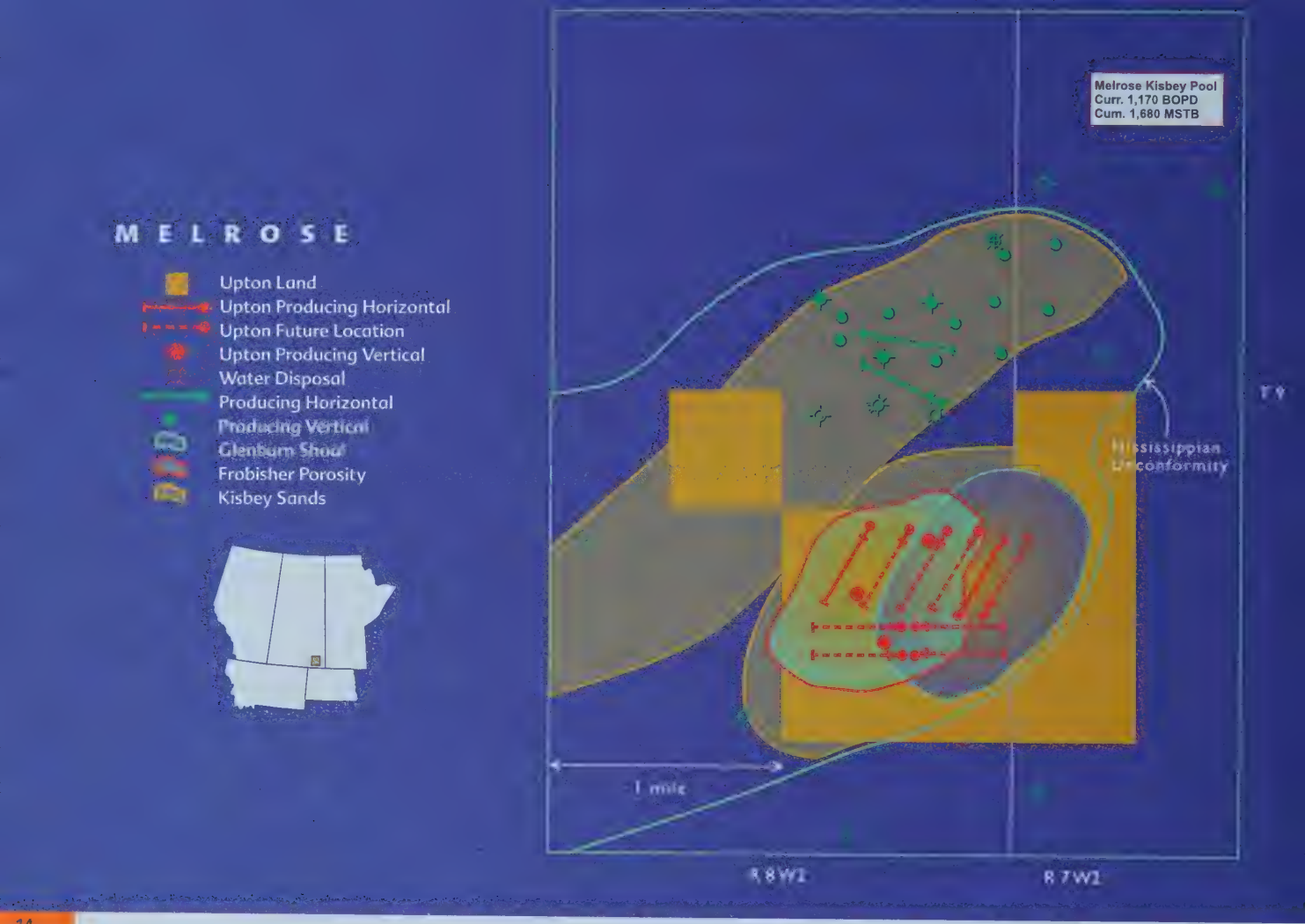
MIDALE

Midale is Upton's largest producing property, a major success story for the Company and a good example of Upton's core competency. Midale contributes low-risk, shallow production from up to six porous intervals in Frobisher Formation carbonates lying beneath an older Midale Formation oil pool owned by others. Upton acquired its 100 percent interest in the undeveloped Frobisher zone in 1997 and 1998, when the rights would have reverted from former leaseholders to the Crown and were offered for sale. Upton generated drilling prospects using information from wells drilled in the 1960s and from new 3D seismic.

Production has been brought from zero to 1,200 barrels per day in three years, primarily using horizontal wells that take only eight to 10 days to drill and cost an average of $650,000 to drill and equip for production. The wellbores target the uppermost Frobisher porosity with open-hole completions of 600-900 metres in length, and producing wells often achieve pay-out in as little as four months.

In 2000, Upton drilled 8 horizontal and 3 vertical producers at Midale, bringing production to an average of 963 barrels per day for 2000, an increase of 120 percent over 1999. Upton has battery and water disposal facilities in place and a pipeline connection to the Enbridge Inc. mainline completed in the first quarter of 2001.

The Company holds 14,190 net acres of undeveloped land at Midale, and has worked up a two-year inventory of drillable prospects. Up to 25 further wells can be added to complete development. In 2001, Upton plans to drill 8 wells at Midale.



MELROSE

At Melrose, Upton recognized the potential for reservoir development in shoals adjacent to the Kisbey channel sands. Through a combination of farm-in and acquisition of Crown acreage, Upton in 1999 captured 1.5 sections on this prospect at a working interest of 100 percent. During 2000, an additional 320 acres were earned at an average working interest of 86 percent. The Company drilled 4 wells in 2000, striking a new reservoir and achieving production of more than 407 barrels per day at year-end 2000, a level Upton can increase through further development drilling. The Company has identified three separate producing zones in the Kisbey, Frobisher and Alida. Up to 6 additional horizontal development wells are planned in 2001. Upton has booked 427,000 barrels of reserves to date and plans to add to this with future drilling.

HARTHAVEN

Harthaven is a 100 percent Upton property eight miles northwest of Melrose. After purchasing 3D seismic data in 1999, Upton recognized the potential to extend the existing Harthaven pool into an area known as Lost Horse Hills. The step-out well was drilled on a section of land acquired by Upton, and at year-end the pool was producing at 291 barrels per day, with proven plus probable reserves of 362,000 barrels. Upton has planned 2 development wells for 2001.

TRACY MOUNTAIN/DAVIS CREEK, NORTH DAKOTA

Tracy Mountain/Davis Creek is a major success story for Upton and has become the Company's second Core Area. The Fryburg reservoir at Davis Creek is a continuation of the Williston Basin edge play in a formation equivalent to the Frobisher beds but at twice the depth, or about 2,800 metres. The reservoir characteristics promise longer-life production and greater reserves per well when using horizontal wellbores that improve access to reservoir porosity. In the course of a year, Upton has driven production from zero to 939 (316 net) barrels per day from two zones. Booked reserves have increased from 700,000 barrels in 1999 to over 2 million barrels at year-end 2000.

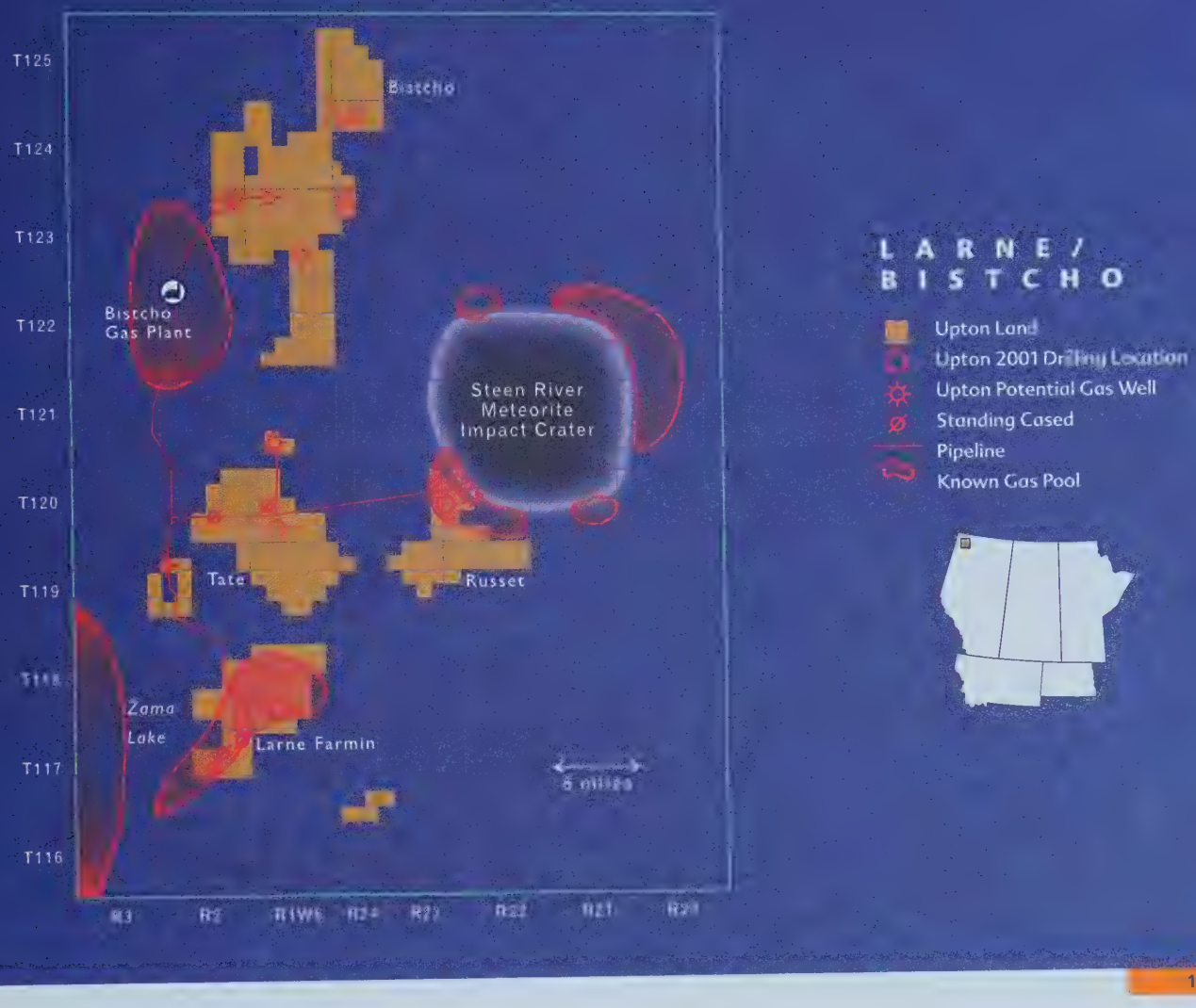
Upton entered the area in 1996 looking for oil in the Mississippian-age Tyler reservoir at Tracy Mountain (adjacent to Davis Creek). Oil in this area is high-quality, 41° API gravity crude that commands a premium price. Upton acquired 7,000 acres of federal lands with a 47.5 percent working interest in the Tyler sand, a Pennsylvanian-age formation younger than the Fryburg. Tyler oil pools drilled north and south of Upton's land produce at 150-450 barrels per day per well and tap reserves of 150,000-800,000 barrels per well.

While drilling a Fryburg test in August 2000, Upton encountered the Tyler sand. Test pressures indicated Upton's well had discovered a new oil pool rather than a mere pool extension. This discovery well was completed as a Fryburg horizontal and came on-production at 250 barrels per day. Upton drilled a subsequent vertical well to bring the Tyler sand on production and will drill follow-up wells in the summer of 2001 to further evaluate the new pool.

At Davis Creek, Upton used data from a competitor's Fryburg horizontal, noted on the accompanying map, to model its Davis Creek prospect. Five years after coming on production the competitor's well is still producing at 150 barrels per day, has cumulative production of 300,000 barrels and ultimate economic recovery estimated at 900,000 barrels. Upton aimed to replicate this performance at its prospects, drilling its first well in late 1999 with a 1,200 metre horizontal completion, and commenced production at 230 gross barrels per day in early 2000. Following on this success, Upton drilled 5 horizontal development wells in 2000, all of which are now on-production. Initial indications are that the production decline will be about 10 percent per year after the first year. This is a low decline rate for oil and gas well production.

Each well is expected to stabilize at about 150 barrels per day and ultimately recover 300,000-900,000 barrels. At current oil prices, payout occurs in approximately 12 months. Upton has up to 18 additional development locations on the Fryburg oil pool using 320 acre spacing. Potential exists to drill at 160 acre spacing. At an average working interest of 37.27 percent, Upton estimates Davis Creek could realize stabilized production of 1,200-1,500 barrels per day net and recoverable reserves of several million barrels upon full development several years out.

Upton's new Core Area will be the scene of an active exploration and development program in 2001. Upton will drill a planned 7 further Fryburg development wells at Davis Creek. At Tracy Mountain, Upton will drill 2 Tyler delineation wells in July and August. Ultimate development could see an additional 8 to 10 wells in excess of 1.0 million barrels. In the same reservoir fairway about five miles southwest of the 2000 discovery, Upton will drill a Tyler exploration well. At Rocky Hill and Square Butte, located within 20 miles of the Davis Creek success, Upton will drill up to 2 Fryburg wildcats at 90-100 percent working interest.



LARNE/BISTCHO

In late 2000, Upton established a third core area in the Larne/Bistcho area of northwest Alberta. This is a natural gas-prone exploration area for Devonian-age Slave Point and Sulphur Point carbonate rocks. The reservoirs lie at depths of 1,200 to 1,600 metres with drilling costs of $600,000 per well. Successful vertical wells can produce from 1.0 to 10 million cubic feet per day of natural gas, tapping reserves of 1 to 5 billion cubic feet per well. The area is lightly drilled and similar in geology to Upton's southeast Saskatchewan production.

Upton entered the area through three separate agreements. These agreements resulted in the purchase of 4 producing wells, shut-in wells capable of production but not tied into a pipeline, and an extensive land base of both held and expiring lands totalling 170,000 acres. Working interest varies from 3.125 percent to 50 percent. Upton will spend $6.5 million dollars in the area in 2001, including participation in the drilling of 13 wells before the end of the 2001 winter drilling season. Five of these wells discovered new gas pools that have been production tested and tied into facilities. Three wells currently drilling will be evaluated for production next winter. Upton hopes to realize net production of 1 to 3 million cubic feet per day with wells to be tied in by the end of April 2001.

Upton's team is extremely excited by the potential of the northwest Alberta core area. Upton will have secured an interest in almost 100,000 acres of land after April with options and drilling commitments on an additional 19,000 acres that will be further evaluated in the next few years. Further opportunities are being pursued in the area to increase Upton's working interest on certain lands. A large amount of open Crown land in the area will allow Upton to pursue promising geological trends as they are identified.

2000 DRILLING PROGRAM

In 2000 Upton invested a total of $29.5 million net on an exploration and development program that included 46 wells (35.6 net) at an average working interest of 77 percent. This program included 26.5 net development wells and 9.1 net exploration wells. Of the total, 21.5 net were horizontal wells. The program resulted in 36 (27.7 net) oil wells, seven (5.7 net) dry holes and three (2.2 net) disposal wells. Upton achieved a success rate of 48 percent on exploration wells and 96 percent on development wells.

2000 DRILLING RESULTS

	Development				Total		Total		Grand	
	Horizontal		Vertical		Development		Exploration		Total	
Wells	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	29	21.5	4	4.0	33	25.5	3	2.2	36	27.7
Dry	0	0.0	1	1.0	1	1.0	6	4.7	7	5.7
Other	0	0.0	0	0.0	0	0.0	3	2.2	3	2.2
Total	29	21.5	5	5.0	34	26.5	12	9.1	46	35.6
Operated	28	21.5	5	5.0	33	26.5	11	8.8	44	35.3
Non-operated	1	0.0	0	0.0	1	0.0	1	0.3	2	0.3
Success rate	100%	100%	80%	80%	97%	96%	50%	48%	85%	84%
Average interest		74%		100%		78%		76%		77%

PRODUCTION

Going into 2000, Upton set an operational goal of achieving production at year-end of 5,000 barrels per day. This target was reached in the second week of December, and production for the month averaged 4,933 barrels per day. During 2000 Upton's production averaged 4,263 barrels per day, an increase of 21 percent over 1999.

MAJOR PRODUCING PROPERTIES

	Current	2000		1999		1998	
Oil (bbls/day)	Jan 31/01	**Volume**	**% of Total**	Volume	% of Total	Volume	% of Total
Alida/Cantal/Queens	835	**1,067**	**25**	787	23	1,082	24
Midale	1,212	**963**	**23**	438	13	365	8
Gainsborough	678	**766**	**18**	815	23	1,215	28
Browning	358	**378**	**9**	388	11	35	1
Harthaven	215	**68**	**1**	0	0	0	0
Melrose	343	**97**	**2**	0	0	0	0
Other	652	**728**	**17**	986	27	1,518	34
U.S. Properties	426	**196**	**5**	108	3	226	5
Total	4,719	**4,263**	**100**	3,522	100	4,441	100

DRILLING, PRODUCTION, LAND BY AREA

Area	2000 Drilled Wells		2000 Average Production		Net Undeveloped Land	Average Land WI	Crude Quality
	Gross	Net	bopd	% of Total	Acres	%	API, deg
Alida/Cantal/Queens	4	2.6	1,067	25	691	63	37
Midale	11	11.0	963	23	14,190	93	29
Gainsborough	4	3.8	766	18	4,298	91	32
Browning	3	2.0	378	9	1,833	92	35
Harthaven	4	4.0	68	1	800	100	27
Melrose	4	3.7	97	2	320	100	28
Other	9	5.5	728	17	76,025	77	-
U.S. Properties	7	3.0	196	5	52,391	74	40
Total	46	35.6	4,263	100	150,548	-	

RESERVES

Total proved and probable reserves at December 31, 2000 were 12.9 million barrels. Proven producing reserves increased to 6.8 million barrels from 6.2 million barrels at year-end 1999, an increase of 537,000 barrels, or 9 percent. Total proven reserves remained at 8.9 million barrels, compared to December 31, 1999. Probable reserves also remained steady at just under 4 million barrels, compared to just over 4 million barrels at December 31, 1999.

The majority of the 2.3 million barrels of additions occurred at Tracy Mountain and Upton's two new properties at Harthaven and Melrose. Proven plus probable additions at these properties totalled 1.4 million barrels and 842,000 barrels, respectively. Significant reserve additions in 2001 are expected to come from Tracy Mountain and Upton's exploration program, particularly the new Larne/Bistcho natural gas play in northwest Alberta. No reserves from this play had been booked at December 31, 2000 due to the majority of drilling taking place in early 2001.

RESERVES RECONCILIATION

	Proven (mbbls)	Probable (mbbls)	Total (mbbls)
Balance December 31, 1999	8,920	4,023	12,943
Additions	1,360	961	2,321
Sale of reserves	-	-	-
Revisions of prior estimates	145	(998)	(853)
2000 production	(1,560)	-	(1,560)
Balance December 31, 2000	8,865	3,986	12,851

MAJOR PROPERTIES RESERVES AND NET PRESENT VALUE

Area	2000 Year-end Reserves (mbbls)				Net Present Value 12%*, M$		
	Proven	Probable	Total	% of Total	Total Proved	Established	% Established
Midale	1,492	1,212	2,704	21	15,908	20,467	19
Gainsborough	1,696	211	1,907	15	16,769	17,554	16
Alida/Cantal/Queens	1,572	214	1,786	14	18,150	18,832	18
Browning	545	40	585	5	6,298	6,644	6
Harthaven	247	115	362	2	3,874	4,555	4
Melrose	275	152	427	3	2,911	3,401	3
Other	1,837	677	2,514	20	17,090	19,249	18
U.S. Properties	1,201	1,365	2,566	20	12,230	16,940	16
Total	8,865	3,986	12,851	100	93,230	107,642	100

* Estimated future net present value before income taxes and Saskatchewan Capital tax, discounted at 12%, from the Reserves Evaluation.

Upton's year-end base of proven plus probable reserves provided a reserve-life index, based on the fourth quarter annualized production, of 7.8 years.

RESERVE LIFE INDEX AND RESERVE REPLACEMENT RATIO

	2000	1999	1998
Reserve Comparison			
Proven (mbbls)	8,865	8,920	10,019
Probable (mbbls)	3,986	4,023	3,793
Total (mbbls)	12,851	12,943	13,812
Established (mbbls)	10,858	10,931	11,916
Q4 annualized production (mbbls)	1,645	1,552	1,360
Reserve Life Index			
Proven (yrs)	5.4	5.7	7.4
Established (yrs)	6.6	7.0	8.8
Total proved and probable (yrs)	7.8	8.3	10.2
Reserve Additions, Net of Revisions			
Proven (mbbls)	1,505	1,182	4,931
Established (mbbls)	1,487	1,326	6,220
Total proved and probable (mbbls)	1,468	1,470	7,509
Reserve Replacement Ratio			
Proven	0.9	0.8	3.6
Established	0.9	0.9	4.6
Total proved and probable	0.9	0.9	5.5

Note: Established is proven plus one-half probable.

Ratios and indexes calculated on fourth quarter annualized production.

Due to the strong oil price and increases in proved producing reserves, Upton's reserve value increased significantly. Net Present Value, using escalated prices, of established reserves before taxes, discounted at 12 percent, increased from $76.4 million at year-end 1999 to $107.6 million at year-end 2000, a gain of 41 percent. The following two tables provide a detailed comparison of Net Present Values.

ESCALATED NPV COMPARISON

Present Value of Future Cash Flow ($ millions)								
	2000				1999			
Discounted at	0%	10%	12%	15%	0%	10%	12%	15%
Total proved	**141.1**	**98.3**	**93.2**	**86.8**	103.5	69.0	65.3	60.6
Probable	**56.0**	**31.4**	**28.8**	**25.6**	42.4	24.1	22.2	19.8
Grand total Proved and probable	**197.1**	**129.7**	**122.0**	**112.4**	145.9	93.1	87.5	80.4
Established	**169.1**	**114.0**	**107.6**	**99.6**	124.7	81.0	76.4	70.5

Note: Estimated future net present value before income taxes and Saskatchewan Capital tax from the Reserves Evaluation.

CONSTANT DOLLAR NPV COMPARISON

Present Value of Future Cash Flow ($ millions)								
	2000 WTI $31.86/bbl*				1999 WTI $24.51/bbl*			
Discounted at	0%	10%	12%	15%	0%	10%	12%	15%
Total Proved	**217.8**	**145.7**	**137.4**	**126.8**	146.4	97.9	92.6	85.9
Probable	**91.7**	**51.8**	**47.6**	**42.4**	60.8	36.5	33.8	30.4
Grand Total Proved and probable	**309.5**	**197.5**	**185.0**	**169.2**	207.2	134.4	126.4	116.3
Established	**263.7**	**171.6**	**161.2**	**148.0**	176.8	116.2	109.5	101.1

* Fourth quarter West Texas Intermediate in U.S. dollars

Note: Estimated future net present value before income taxes and Saskatchewan Capital tax from the Reserves Evaluation.

CRUDE OIL ESCALATING PRICE FORECAST AS OF JANUARY 2001

Year	WTI @ Cushing (U.S./bbl)	CDN/U.S. Exchange Rate	WTI @ Cushing (U.S./bbl)	EDM Ref Price ($/bbl)($)
2001	27.00	0.660	40.91	39.91
2002	24.00	0.670	35.82	34.80
2003	23.00	0.680	33.82	32.78
2004	23.00	0.690	33.33	32.27
2005	23.46	0.700	33.51	32.43
2006	23.93	0.700	34.18	33.08
2007	24.41	0.700	34.87	33.74
2008	24.90	0.700	35.57	34.42
2009	25.39	0.700	36.28	35.11
2010	25.90	0.700	37.00	35.81
2011	26.42	0.700	37.74	36.52
2012	26.95	0.700	38.50	37.25
2013	27.49	0.700	39.27	38.00
2014	28.04	0.700	40.05	38.76
2015	28.60	0.700	40.85	39.53

COST CONTROL AND OPERATING NETBACKS

Upton has maintained its position as one of the lowest cost operators in the Canadian oil industry. The Company's operating costs for 2000 were $3.80 per barrel vs $4.22 per barrel in 1999, a decrease of 10 percent. Not only were operating costs low for 2000, they were consistent with past years, bringing the five-year operating costs average to $3.61 per barrel. The main contributors to this low cost efficiency were Upton's field staff. This was accomplished through their commitment to ensure low costs without sacrificing quality of equipment, manpower, services, safety, and environmental concerns.

Upton continues to use technology to capture field data information on a daily basis for analysis and monitoring of production data. This information is compiled on a weekly basis and allows precise monitoring of production and cash flow and immediate response to any interruptions in production.

($/bbl)	**2000**	1999	1998	1997	1996
Cash netback	**18.64**	8.94	7.66	12.94	13.84
Operating cost	**3.80**	4.22	3.68	3.65	2.70

Cash netbacks improved dramatically from 1999 to 2000. Average cash netbacks were $18.64 per barrel in 2000 compared to $8.94 per barrel in 1999, an increase of 109 percent. Upton believes that if world oil prices average $26 WTI it will be able to maintain netbacks at this level. Netbacks will be enhanced by an even stronger gas price and the addition of gas to Upton's portfolio.

2001 CAPITAL PROGRAM

For 2001, Upton has budgeted a capital program totalling $32.8 million ($25.6 million net of property dispositions). This will fund drilling of 27.3 net wells and is aimed at increasing Upton's production by 5 percent to an average of 4,500 barrels per day net of property dispositions. For the first time, Upton's production will include a natural gas component — albeit a small one at an estimated 750,000 cubic feet per day average for the year — but following another winter season of drilling and tie-ins of wells drilled this season, natural gas volumes should grow.

The budget will be allocated by Core Area as follows: southeast Saskatchewan $17.8 million or 54 percent of total expenditures, North Dakota $8.5 million or 26 percent, and northwest Alberta $6.5 million or 20 percent. Development drilling will focus primarily on increasing production and reserves at Tracy Mountain/Davis Creek, with a target of more than 800 barrels per day net by year-end.

A significant proportion of expenditures — $14 million or 43 percent — will be directed to exploration. This will include spending on acquisitions, drilling and facilities of $6.5 million on a multi-well program at Larne/Bistcho, Fryburg exploration in the vicinity of Davis Creek, vertical stratigraphic tests at Florence in southeast Saskatchewan plus land acquisitions and seismic work. Upton does not include any oil exploration volumes in its 4,500 barrels per day forecast and has included modest volumes of natural gas production during 2001. Including the acquisition of Larne of $1.5 million, Upton is targeting additional property acquisitions budgeted at $2.6 million.

MANAGEMENT'S DISCUSSION AND ANALYSIS

(all tabular figures in thousands of dollars, unless otherwise noted)

HIGHLIGHTS

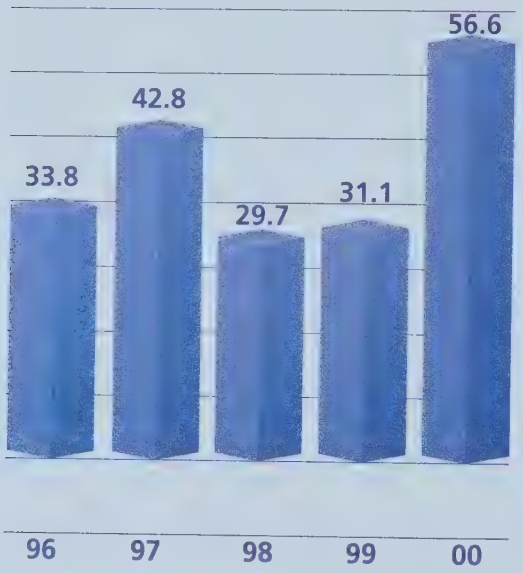
The highlights of Upton Resources Inc.'s financial performance for the year ended December 31, 2000 are summarized as follows:

- Revenue increased by 82 percent over 1999 to $56.6 million on 1.6 million barrels of total production.
- Realized oil price net of hedges increased by 50 percent over 1999 to $36.28 per barrel.
- Daily average production increased by 21 percent to 4,263 barrels per day from the 1999 average of 3,522 barrels per day.
- Operating costs decreased by 10 percent over 1999 to $3.80 per barrel of production.
- Cash netbacks increased by 109 percent to $18.64 per barrel in 2000 from $8.94 per barrel in 1999.

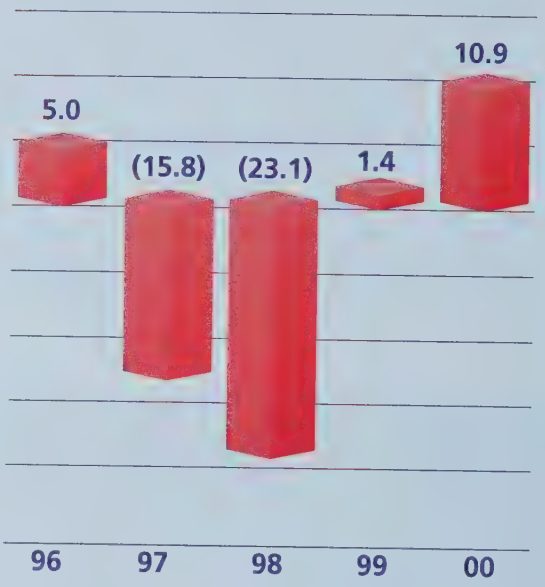
- Basic cash flow from operations was $29.1 million, up by 153 percent from 1999, or $1.67 per share, an increase of 157 percent from 1999.
- The depletion and depreciation provision was $12.4 million, an increase of 86 percent from $6.7 million in 1999.
- Net earnings were $10.9 million, or $0.63 basic per share, compared to $1.4 million or $0.08 basic per share in 1999.
- The year-end debt to trailing cash flow from operations ratio decreased to 0.9 to 1.0 in 2000 from 2.2 to 1.0 as of December 31, 1999.
- Canadian income tax pools decreased by 4 percent to $64.2 million.
- Net capital expenditures were $29.5 million, up by 167 percent from 1999.
- Reserve additions, net of revisions, totalled 1.5 million barrels.
- Finding and development costs for total reserves were $20.14 per barrel in 2000, yielding a three-year average of $6.48 per barrel.

FINANCIAL PERFORMANCE

Revenue ($ mm)



Earnings ($ mm)



Cash Netback ($ per barrel)

Long Term Debt to Cash Flow Ratio ($ mm)

OPERATING INCOME

	2000	1999	% Change	1998
Crude oil sales	**63,906**	33,234	92	28,605
Hedge	**(7,290)**	(2,095)	(248)	1,108
Net realized oil revenue	**56,616**	31,139	82	29,713
Royalties	**14,242**	8,172	74	6,157
Production expenses	**5,926**	5,428	9	5,959
Operating Income	**36,448**	17,539	108	17,597
Netbacks ($/barrel)				
Sales price	**36.28**	24.22	50	18.33
Royalties	**9.13**	6.36	44	3.80
Production expenses	**3.80**	4.22	(10)	3.68
Operating netback	**23.35**	13.64	71	10.85

Upton's operating income increased by 108 percent over 1999 to $36.4 million in 2000. Revenues increased by 82 percent over 1999 as a result of a 21 percent increase in production volumes and a 50 percent increase in realized product prices net of hedging losses compared to 1999. Strong oil prices resulted in total hedging losses of $7.3 million ($4.68 per barrel) in 2000.

Royalties increased by 74 percent for the year as a result of higher production and wellhead revenue. Total production expenses increased by 9 percent over 1999 due to the increased production volumes for the year.

PRODUCTION EXPENSES

	2000	1999	% Change	1998
Production volume (thousands of barrels)	**1,560**	1,285	21	1,621
Production expense ($thousands)	**5,926**	5,428	9	5,959
Per barrel ($)	**3.80**	4.22	(10)	3.68

Upton's unit operating costs decreased to $3.80 per barrel in 2000 from $4.22 in 1999 as a result of the fixed portion of operating costs being applied to a higher rate of production for the period.

GENERAL AND ADMINISTRATIVE EXPENSES

	2000	1999	% Change	1998
Gross expense	**5,094**	4,784	6	4,602
Less recoveries:				
Overhead	**1,688**	1,330	27	1,676
Capitalized G&A	**472**	584	(19)	579
Net expenses	**2,934**	2,870	2	2,347
Average cost ($ per barrel)				
Gross	**3.27**	3.72	(12)	2.84
Net	**1.88**	2.23	(16)	1.45
Number of employees				
Head office	**25**	25	-	26
Field operations	**14**	13	8	12
Total employees	**39**	38	3	38

Staff levels remained almost constant through 2000 and 1999, resulting in little change to the gross G&A costs. The year 2000 involved a full year of drilling and completion activity, compared to a half year's activity in 1999, resulting in a higher rate of overhead recoveries. Capitalized G&A recoveries decreased by 19 percent in 2000, which included a decrease in the base of capitalized land department costs. These factors left net G&A expenditures unchanged in 2000. Per barrel decreases in 2000 reflect static costs at higher production levels.

INTEREST AND FINANCIAL EXPENSE

	2000	1999	% Change	1998
Credit facility	**1,872**	1,600	17	1,365
Debenture	**294**	353	(17)	353
Acquisition	**-**	-	-	-
Disposals	**-**	(37)	100	-
Flow-through share part 12 tax	**-**	75	(100)	-
Total	**2,166**	1,991	9	1,718
Average cost ($ per barrel)	**1.39**	1.55	(10)	1.06

Upton's primary borrowings are through its bank line of credit. The average draw on this line in 2000 was unchanged from 1999 at $24.2 million. Interest expense from the credit facility increased by 17 percent to $1.9 million in 2000, due to the increase in the average annual prime interest rate from 6.43 percent in 1999 to 7.24 percent in 2000. The debenture's interest expense decreased by 17 percent as interest payments ceased on October 31, 2000 when the debenture was repaid.

CURRENT AND CAPITAL TAXES

	2000	1999	% Change	1998
Federal capital taxes	**32**	64	(50)	120
Saskatchewan capital taxes	**2,216**	1,124	97	994
Current taxes	**-**	-	-	-
Total current and capital taxes	**2,248**	1,188	89	1,114

Saskatchewan capital taxes are 3.6 percent of oil and gas revenue from production in the province. The year-over-year increase of 97 percent in capital taxes to $2.2 million tracked the increase in oil revenue earned in Saskatchewan.

CASH FLOW FROM OPERATIONS

	2000	1999	% Change	1998
Cash flow from operations	**29,100**	11,490	153	12,418
Production netbacks ($/barrel)				
Crude sales	**40.96**	25.85	58	17.65
Hedge	**(4.68)**	(1.63)	(187)	0.68
Net realized oil sales	**36.28**	24.22	50	18.33
Less:				
Royalties	**9.13**	6.36	44	3.80
Operating expenses	**3.80**	4.22	(10)	3.68
Operating netback	**23.35**	13.64	71	10.85
General and administrative	**1.88**	2.23	(16)	1.45
Interest	**1.39**	1.55	(10)	1.06
Current and capital tax	**1.44**	0.92	57	0.68
Cash netback	**18.64**	8.94	109	7.66
Production volume (thousands of barrels)	**1,560**	1,285	21	1,621

Upton's cash flow from operations increased by 153 percent to $29.1 million in 2000. This was a result of the 109 percent increase in cash netbacks, which was due to a combination of higher per barrel revenue, lower per barrel costs and the 21 percent increase in production volumes for the year.

DEPLETION, DEPRECIATION, ABANDONMENT AND RESTORATION

	2000	1999	% Change	1998
Depletion and depreciation	**12,401**	6,682	86	13,427
Ceiling test write-down	**0**	0	-	34,800
Restoration provision	**832**	784	6	1,099
Total	**13,233**	7,466	77	49,326
Average cost ($ per barrel)	**8.48**	5.81	46	8.96*

* Excluding write-down provision

Depletion and depreciation expenses increased to $12.4 million in 2000 from $6.7 million in 1999. This can be attributed to the following factors: a $29.5 million increase in fixed assets in the year, the higher level of production being applied to the rate in the year, relatively flat proven reserves over the year and the increased depletion of the U.S. company's fixed assets with the increased production from the U.S. properties in the year.

The abandonment provision increased by 6 percent over 1999 to $0.8 million for the year.

FUTURE TAXES

	2000	1999	% Change	1998
Future tax benefit	**7,404**	12,343	(40)	15,858*
Future tax (recovery) provision	**4,942**	2,613	89	(13,765)*

* Restated in 1999

In December 1999, Upton adopted the Canadian Institute of Chartered Accountants' new standard of accounting for income taxes. Under the new standard, future income taxes are recognized for all differences between accounting and tax values of assets and liabilities, based on current income tax rates. Previously, such differences were charged to income in future years as the assets were depleted or depreciated. Upton restated the financial statements for 1998 to record the change retroactively for comparative purposes.

In 2000, Upton's future income tax benefit was $7.4 million, compared to a 1999 benefit of $12.3 million. Upton realized a benefit of $15.9 million in 1998, which was primarily a result of the December 31, 1998 ceiling test write-down, which reduced the Company's net book value of oil and gas assets below the value of its tax pools.

The future tax benefit of $7.4 million is represented by $6.0 million in the Canadian tax jurisdiction and $1.4 million from Upton's U.S. subsidiary. Upton USA Inc. has an additional U.S. $2.1 million of costs and losses representing tax value in excess of net book value which is not recorded as a future tax benefit. Upton's U.S. operations are at an early stage of development. Therefore a record of profitability, which would allow the Company to conclude that the utilization of all of these future tax benefits is "more likely than not," has not yet been met.

NET EARNINGS

	2000	1999	% Change	1998
Cash flow from operations	**29,100**	11,490	153	12,418
Less:				
Depletion	**12,401**	6,682	86	13,427
Ceiling test write-down	**0**	0	-	34,800
Site restoration	**832**	784	6	1,099
Future tax (recovery) provision	**4,942**	2,613	89	(13,765)*
Net earnings (Loss)	**10,925**	1,411	674	(23,143)*

* Restated

A significantly improved pricing environment and higher production volumes throughout 2000 resulted in earnings in 2000 of $10.9 million.

CAPITAL EXPENDITURES, RESERVE ADDITIONS AND FINDING COSTS

	2000	1999	% Change	1998
Property acquisitions	**338**	1,082	(69)	3,086
Property dispositions	**0**	(5,094)	100	(479)
Land and other	**2,556**	1,077	137	2,301
Exploration and development	**19,199**	10,381	85	10,052
Equipment and facilities	**7,025**	2,908	142	4,808
Capitalized overhead	**472**	584	(19)	579
Corporate (excluded from finding costs)	**(43)**	121	(136)	97
Total net capital expenditures	**29,547**	11,059	167	20,444
Reserve additions, net of revisions and sales (mbbls)				
Proven	**1,506**	187	705	4,931
Probable	**(37)**	230	(116)	2,578
Total reserve additions (mbbls)	**1,469**	417	252	7,509
Finding costs ($ per barrel)				
Proven	**19.65**	58.49	(66)	4.13
Proven plus probable	**20.14**	26.23	(23)	2.71
Three-year rolling average				
Proven	**9.19**	12.47	(26)	10.84
Proven and probable	**6.48**	8.94	(28)	8.29

Upton's net capital expenditures increased by 167 percent in 2000 to $29.5 million, which compared to cash flow of $29.1 million for the year. 35.6 net wells were drilled in 2000 compared to 22.0 in 1999, resulting in exploration and development expenditures of $19.2 million. Facility additions and enhancements at Melrose, Harthaven, Tracy Mountain and Midale increased equipment and facility costs by 142 percent over 1999 to $7 million. The Company's $29.5 million in capital expenditures is comprised of $23.7 million in Canada and $5.8 million in the U.S., reflecting the Company's increased activity in the U.S. Two minor acquisitions for $0.3 million increased the Company's net working interest in the Queensdale and Wildwood properties.

Upton drilled 46 wells (35.6 net) during the year, which included 9.1 net exploration wells and 26.5 net development wells. The drilling program attained a success rate of 48 percent on exploration wells and 96 percent on development wells.

With the improved oil prices in the year, the Company was able to increase its drilling and facility development program in Canada and the U.S.

NET ASSET VALUES

	2000 Escalating Price			1999	
	10%	12%	15%	15%	% Change
Established					
Reserves (mbbls)*	10,858	10,858	10,858	10,931	(0)
Net resource value*	$ 107,027	$ 101,144	$ 93,642	$ 65,219	44
Net land value**	$ 10,538	$ 10,538	$ 10,538	$ 11,786	(11)
Business assets	$ 117,565	$ 111,682	$ 104,180	$ 77,005	35
LTD and working capital deficit	$ (30,119)	$ (30,119)	$ (30,119)	$ (28,316)	(6)
Net asset value	$ 87,446	$ 81,563	$ 74,061	$ 48,689	52
Outstanding shares (thousands)	17,196	17,196	17,196	17,731	(3)
Net asset value per share	$ 5.09	$ 4.74	$ 4.31	$ 2.75	57

* Probable values have been reduced by 50 percent for risk. Net resource values are after deduction for Saskatchewan capital tax.

** Net land value — 2000 (150,548 acres @ $70/acre) 1999 (166,130 acres @ $71/acre

At December 31, 2000, Upton's net asset value, discounted at 15 percent, was $4.31 per share. This is an increase of 57 percent from $2.75 in 1999, as a result of higher forecast oil prices and the movement of over one million barrels of reserves to the proven and probable producing category.

INCOME TAX POOLS

	2000	1999	% Change	1998
Canadian Oil and Gas Property Expense	24,629	25,521	(3)	30,818
Canadian Development Expense	20,695	17,867	16	23,060
Canadian Exploration Expense	4,774	12,213	(61)	4,906
Undepreciated Capital Cost	14,142	11,024	28	12,288
Total Canadian tax pools	64,240	66,625	(4)	71,072
United States tax pools and losses (U.S.$)	14,423	11,208	29	10,938

The Company's Canadian Oil and Gas Property Expense tax pool (10 percent annual claim), Canadian Development Expense tax pool (30 percent annual claim), Canadian Exploration Expense tax pool (100 percent annual claim) and Undepreciated Capital Cost pools were reduced by 4 percent by year-end. The increased level of development drilling and facility additions resulted in increases to the Canadian Development Expense pool and the Undepreciated Capital Cost pool of 16 percent and 28 percent, respectively. The Canadian Exploration Expense pool was reduced by $7.4 million as this pool was required to eliminate any current Canadian tax.

In the United States, costs and losses of U.S. $14.4 million are available to be claimed against future taxable income. Upton recognized U.S. $0.9 million (Cdn $1.4 million) of U.S. future tax assets on the excess amount of U.S. tax costs and losses above their net book value. The Company has significant tax pools to shield it from income tax in Canada and the U.S.

LONG-TERM DEBT

	2000	1999	% Change	1998
Long-term debt balance - opening	**22,342**	26,135	(15)	16,595
Less:				
Share issue - flow-through	**-**	347	(100)	2,645
Share issue - options	**114**	15	660	336
Cash flow from operations	**29,100**	11,490	153	12,418
Dispositions of property and equipment	**-**	3,962	(100)	479
Change in working capital	**(55)**	1,179	(105)	(4,419)
Current portion of long-term debt	**(3,000)**	3,000	(200)	-
Plus:				
Additions to property and equipment	**29,547**	16,153	83	20,923
Site restoration expenditures	**42**	-	100	-
Shares purchased and cancelled	**1,428**	47	2,938	76
Net increase (decrease) - long-term debt	**4,858**	(3,793)	228	9,540
Long-term debt balance - closing	**27,200**	22,342	22	26,135

LIQUIDITY AND FINANCIAL RESOURCES

The Company's financial strategy is to fund capital expenditures from cash flow, supplemented by credit facilities and equity issues when appropriate. Upton targets its long-term debt to be approximately 1.0 times the next year's forecast cash flow from operations, using an oil price assumption of U.S. $20 per barrel of WTI crude oil. The high oil prices and increased drilling activity throughout the year substantially improved the Company's year-end debt to 12-month trailing cash flow from operations ratio to 0.9 times from 2.2 times at year-end 1999. Using fourth quarter annualized cash flow, the ratio improves to 0.8 times. Using a 2001 average oil price of U.S. $26.00 per barrel of WTI, the Company anticipates its year-end ratio to be approximately 0.8 times.

Upton's authorized credit, all of which is secured, was $34 million at year-end. It is comprised of a $32 million revolving demand credit facility and a $2 million secondary demand credit facility, to be used for acquisitions and/or development drilling.

At December 31, 2000, $27.2 million was drawn on the revolving credit facility and nothing was drawn on the secondary demand loan, leaving $6.8 million available for additional capital expenditures and working capital needs. No principal repayments under the facility agreement are anticipated in 2001.

For the year ended December 31, 2000, Upton had 17,195,840 common shares issued and outstanding. This balance reflects 600,175 shares repurchased and cancelled by normal course issuer bid and 1,606 shares purchased from former employees and subsequently cancelled and 67,000 employee options being exercised for net proceeds of $114,000.

During the year a total of 7,031,308 million Upton common shares traded on The Toronto Stock Exchange, with a high of $3.30, a low of $2.05 and a closing price at December 31, 2000 of $2.61 per share. For the year ended December 31, 2000, the directors and officers of the Company beneficially owned 2,685,784 or 15.6 percent of the common shares.

FUTURE BUSINESS PROSPECTS

INDUSTRY ENVIRONMENT

The price of crude oil is affected by global events of an economic, political and environmental nature. These factors may cause an imbalance of supply and demand, which in turn affects the price of oil. The world supply and demand balance directly affects the wellhead oil price realized by Canadian producers. This price impact directly impacts cash flow and, therefore, the levels of capital expenditures, growth and opportunities for success.

OIL PRICES

During 1999 the price of oil began the year at a historically low level of approximately U.S. $12 per barrel of WTI, and began to improve rapidly in the second quarter. Solidarity among OPEC (Organization of Petroleum Exporting Countries) members remained stronger than during previous attempts to boost prices through production cutbacks. As well, world oil consumption resumed growth thanks to strengthening economies, while downstream constraints also worked to sustain prices. Consequently, a strong average 2000 oil price of U.S. $30.20 resulted.

The value of the Canadian dollar against its U.S. counterpart also influences prices realized by Canadian producers. Producers benefit from a lower Canadian dollar since their commodity price correlates closely to the U.S. WTI NYMEX index. Through 2000, strong oil prices were complemented by a weakening Canadian dollar. Prices are also affected by the quality differential between the various grades of crude oil. More than 70 percent of Upton's oil production is light oil, which commands a premium Canadian price less shipping costs, while the remainder is a high quality, medium grade which in currently blended to light oil.

2001 OPERATIONS

Upton's 2001 budget assumes an average crude oil price of U.S. $26.00 WTI for the year and $5.50 per thousand cubic feet for natural gas, and average Company production of 4,500 barrels of oil equivalent per day. This generates cash flow from operations of $30 million, basic cash flow from operations per share of $1.75, net earnings of $8.0 million and basic net earnings per share of $0.47.

Under these assumptions, Upton expects to fund its planned $32.8 million capital spending program with $30 million of cash flow and a portion of the $7.2 million of proceeds from the asset disposition. The draw on bank lines will be reduced by $4.4 million. Of the $32.8 million budgeted for capital expenditures, $14 million will be directed towards exploration activities and $18.8 million towards development programs.

The oil price assumption translates to a Canadian wellhead price realization of $34.75 per barrel, after accounting for the quality and transportation differential and converting at an estimated annual average exchange rate of 1.48 Canadian dollars to one U.S. dollar. Additional key assumptions are average oil royalties at 24 percent of revenue and lease-operating expenditures averaging $4.36 per barrel of production. Natural gas assumptions are $5.50 per thousand cubic feet with a 25 percent royalty and $1.20 operating cost. Included in the 4,500 barrels of oil equivalent per day target is a 750,000 cubic feet per day average for 2000, resulting in 125 barrels of oil equivalent, converted at 6:1. General, administrative and interest costs are to remain relatively unchanged from 2000.

Entering 2001, world oil prices were indicating relative stability, as the price stayed within the range of U.S. $27-$30 per barrel of W.T.I. during the first two months, due largely to OPEC's continuing adjustment to oil supply.

CASH FLOW SENSITIVITIES

Net of Hedges in Place	Impact on Cash Flow ($thousands)	$ per Share
Oil price change (U.S.$1/bbl WTI)	1,179	0.07
Oil production volume change (100 bbls per day)	764	0.04
Interest rate change (one percent)	278	0.02
Exchange rate change (Cdn$0.01)	252	0.01

Cash flow from operations depends on a number of factors, some of which are not within Upton's control. The table above indicates Upton's sensitivities to variations from the anticipated industry environment.

OPERATIONAL RISKS AND MITIGATING STRATEGY

RISK	MITIGATING STRATEGY
Recruiting and retaining quality professional staff.	Employing only qualified, experienced and professional staff supported by competitive compensation programs.
Finding and developing economical petroleum reserves.	Continuing to focus in areas where the Company has core competency.
Maintenance of reservoir production performance.	Proactive maintenance and the application of current technologies.
Marketing oil production.	Contracting marketing functions to experienced, proven third-party marketing professionals.
Accidental failure of various equipment used to find and develop reserves.	Maintain prudent levels of insurance for all possible contingencies.
Employee and third party, environmental and safety.	Providing ongoing safety and environmental courses and training for all applicable staff.

FINANCIAL RISKS AND MITIGATING STRATEGY

RISK	MITIGATING STRATEGY
Negative effects of market-driven commodity price.	Management has the authority to hedge the price of up to 50 percent of oil production. The Company is exploring for natural gas in the first quarter 2001 to diversify its commodity mix.
Negative effects of foreign exchange rate fluctuations.	Foreign exchange rate changes have a relatively minor impact on Upton's cash flow. However, foreign exchange hedge contracts are purchased where appropriate to mitigate the impact of fluctuations in the exchange rate.
Debt levels and the negative effects of interest rate changes.	The Company maintains a policy of long-term debt at less than 1.5 times annual cash flow. The continuation of current oil prices in 2001 and proceeds from asset sale of $7.2 million in the first quarter 2001 will allow the Company to comfortably maintain this ratio. Due to current low interest rates, fluctuations in the interest rate have a relatively minor impact on Upton's cash flow.

REGULATORY RISKS AND MITIGATING STRATEGY

RISK	MITIGATING STRATEGY
Government energy policies, taxation laws and operational laws.	Upton follows all rules and regulations required by government policies and procedures. The Company carefully monitors government policies that could significantly affect the firm.
Environmental issues, community, resident and employee needs.	All facilities are routinely maintained under high regulatory and Company standards.

MANAGEMENT'S STATEMENT OF RESPONSIBILITY

The accompanying consolidated financial statements of Upton Resources Inc. were prepared by and are the responsibility of management. They have been prepared in conformity with Canadian generally accepted accounting principles. The financial information in the annual report has been reviewed to ensure consistency with the financial statements.

Management maintains systems of internal accounting control designed to provide reasonable assurance that all transactions are properly recorded in the Company's book of accounts, that procedure and policies are adhered to and that assets are safeguarded from unauthorized use.

PricewaterhouseCoopers LLP, an independent firm of chartered accountants, has been engaged, as approved by the shareholders' vote at the last annual meeting, to examine the consolidated financial statements in accordance with Canadian generally accepted auditing standards and provide an independent professional opinion.

The audit committee is composed of four members of the Board of Directors and meets quarterly with the financial officer of the Company. The external auditors of the Company have access to the audit committee to review the planning and scope of testing and to discuss the results of their audited work. The external auditors issue a management letter. On the recommendation of the audit committee, the consolidated financial statements have been approved by the Board of Directors.

G. Scott Dutton
President and Chief Executive Officer
February 16, 2001

Philip H. Grubbe, C.A.
Vice President, Finance and Chief Financial Officer

AUDITORS' REPORT

To the Shareholders of Upton Resources Inc.

We have audited the consolidated balance sheets of Upton Resources Inc. as at December 31, 2000 and 1999 and the consolidated statements of operations, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2000 and 1999 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta
February 16, 2002
(Except for note 12 which is as at March 20, 2001)

CONSOLIDATED BALANCE SHEETS

AS AT DECEMBER 31, 2000 AND 1999

(in thousands of dollars)	2000 $	1999 $
Assets		
Current assets		
Accounts receivable	**9,609**	7,992
Future income tax benefit (note 7)	**7,404**	12,343
Property and equipment (note 4)	**64,340**	47,194
Total assets	**81,353**	67,529
Liabilities		
Current liabilities		
Accounts payable	**12,528**	10,966
Current portion of long term debt (note 5)	**0**	3,000
	12,528	13,966
Long-term debt (note 5)	**27,200**	22,342
Abandonment and restoration provision	**3,350**	2,560
Total liabilities	**43,078**	38,868
Shareholders' equity		
Capital stock (note 6)	**10,167**	10,404
Retained earnings	**28,108**	18,257
Total shareholders' equity	**38,275**	28,661
Total liabilities and shareholders' equity	**81,353**	67,529

Approved by the Board of Directors

W.R. Dutton

Director and Chairman of the Board

G.H. Huntington, C.A.

Director and Chairman of the Audit Committee

CONSOLIDATED STATEMENTS OF OPERATIONS

FOR THE YEARS ENDED DECEMBER 31, 2000 AND 1999

(in thousands of dollars)	2000 $	1999 $
Revenue		
Oil production	**56,616**	31,139
Less: Royalties and production taxes	**14,242**	8,172
	42,374	22,967
Expenses		
Production and operation	**5,926**	5,428
General and administration	**2,934**	2,870
Interest on long-term debt	**2,166**	1,991
Depletion and depreciation (note 4)	**12,401**	6,682
Abandonment and restoration provision	**832**	784
	24,259	17,755
Earnings before taxes	**18,115**	5,212
Income taxes (note 7)		
Capital taxes	**2,248**	1,188
Future taxes	**4,942**	2,613
	7,190	3,801
Net earnings for the year (note 10)	**10,925**	1,411
Earnings per share		
- Basic	**0.63**	0.08
- Fully diluted	**0.58**	anti-dilutive

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

FOR THE YEARS ENDED DECEMBER 31, 2000 AND 1999

(in thousands of dollars)	2000 $	1999 $
Retained earnings (deficit) — beginning of year	**18,257**	(28,267)
Reduction to stated capital (note 6)	**-**	45,113
Normal course issuer bid purchases (note 6)	**(1,074)**	-
Net earnings	**10,925**	1,411
Retained earnings — end of year	**28,108**	18,257

CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR YEARS ENDED DECEMBER 31, 2000 AND 1999

(in thousands of dollars)	2000 $	1999 $
Cash provided by (used in)		
Operating activities		
Net earnings for the year	**10,925**	1,411
Items not affecting cash		
Depletion and depreciation	**12,401**	6,682
Abandonment and restoration provision	**832**	784
Future income taxes	**4,942**	2,613
Cash flow from operations	**29,100**	11,490
Net increase in non-cash operating working capital balances	**(1,402)**	(2,085)
	27,698	9,405
Financing activities		
Increase (decrease) in long-term debt	**1,858**	(793)
Net (purchase) issue of capital stock	**(1,314)**	315
	544	(478)
Investing activities		
Additions to property and equipment	**(29,547)**	(16,153)
Proceeds on sale of property and equipment	**-**	3,962
Site restoration expenditures	**(42)**	-
Net decrease in non-cash working capital balances	**1,347**	3,264
	(28,242)	(8,927)
Cash — beginning and end of year	**-**	-
Cash expended on interest	**$ 2,257**	$ 2,090
Cash expended on taxes	**$ 2,502**	$ 1,189
Cash flow from operations per share		
- Basic	**$ 1.67**	$ 0.65
- Fully diluted	**$ 1.54**	$ 0.62

1. COMPANY ACTIVITIES

The Company is incorporated under the laws of Saskatchewan and its principal activity is the exploration, development and production of oil properties.

2. SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include those of the Company and its wholly-owned subsidiary, Upton Resources U.S.A., Inc.

JOINT VENTURES

Substantially all exploration and production activities are conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

PROPERTY AND EQUIPMENT

a) Capitalized costs

The Company follows the full cost method of accounting, whereby all costs related to acquisition, exploration for and development of oil reserves, whether productive or unproductive, are capitalized and accumulated in separate cost centres for Canada and the United States. Proceeds from the disposition of oil properties reduce capitalized costs with no gain or loss recognized unless such disposition would significantly alter the depletion and depreciation rate.

The Company applies a ceiling test to capitalized costs on an annual basis to ensure that such costs do not exceed estimated future net revenues from production of proven reserves, plus the cost of undeveloped properties net of impairment less development costs of proven undeveloped reserves, administrative, financing, and applicable income and capital tax costs.

b) Depletion and depreciation

Depletion and depreciation of resource properties and equipment are provided on the unit of production method based on total proven reserves before royalties. Unproven properties are excluded from the depletion calculation until quantities of proven reserves or impairment can be determined.

Depreciation on building, vehicles and office equipment is computed using the diminishing balance method at annual rates of 5% to 30%.

c) Flow-through shares

The resource expenditure deductions related to exploratory activities funded by flow through share arrangements are renounced to investors in accordance with tax legislation. A future tax liability is recognized and share capital is reduced by the estimated tax cost of the renounced expenditures.

ABANDONMENT AND RESTORATION PROVISION

The annual provision for future abandonment and site restoration costs is based on estimates made by management and is charged to income using the unit of production method where the ratio of current year production to proven reserves determines the proportion of site restoration costs to be expensed. The accumulated amount represents the aggregate of such annual provisions less the aggregate of actual site restoration expenses incurred and adjustments resulting from property dispositions.

FOREIGN CURRENCY TRANSLATION

The Company translates the foreign denominated monetary assets and liabilities of integrated foreign operations at the exchange rate prevailing at the year end, non-monetary assets and liabilities are translated at historical rates of exchange, and revenues and expenses are translated at the monthly average rate of exchange. Exchange gains and losses arising on translation of the accounts are included in consolidated earnings unless related to long-term items, in which case they are deferred and recognized over the life of the related item.

HEDGING ACTIVITIES

The Company enters into contracts to hedge crude oil prices on a portion of its crude oil production to protect its future earnings and cash flows from the potential adverse impact of low crude oil prices and not for speculative purposes. Gains or losses on these contracts are included in revenues at the time of sale of the related hedged production.

In addition, the Company enters into contracts to fix the U.S./Canadian dollar exchange rate. Gains or losses on these contracts are included in revenues as the monthly contract expires.

INCOME TAXES

The Company follows the liability method of tax allocation accounting. Under this method, recognition of a future tax liability or asset is dependent on the expected tax outflow or benefit to be derived from differences between the carrying value and tax basis of assets and liabilities.

STOCK BASED COMPENSATION PLANS

The Company has stock based compensation plans. These are described in note 6. No compensation expense is recognized for these plans when stock options are issued to employees. Any consideration paid by employees on exercise of stock options or purchase of stock is credited to share capital.

EARNINGS PER SHARE

Earnings and cash flow per share are calculated using the weighted average number of common shares outstanding during the year. Fully diluted earnings and cash flow per share are calculated after giving effect to the exercise of outstanding options.

3. CHANGE IN ACCOUNTING POLICY

In 1999, the Company changed from the deferral method of accounting for income taxes to the liability method in accordance with the new standard set by the Canadian Institute of Chartered Accountants. This change in accounting policy was applied retroactively with restatement of prior periods and resulted in an increase in future tax expense of $2.6 million for 1999.

4. PROPERTY AND EQUIPMENT

AS AT DECEMBER 31, 2000 AND 1999	2000 $	1999 $
Petroleum Properties	**203,008**	173,418
Other property and equipment	**3,039**	3,082
	206,047	176,500
Less: Accumulated depletion and depreciation	**141,707**	129,306
	64,340	47,194

Capitalized expenditures relating to unproven properties which includes land costs and related seismic costs excluded from the depletion base are as follows:

AS AT DECEMBER 31, 2000 AND 1999	2000 $	1999 $
Canada	**983**	2,374
United States	**2,575**	1,581
	3,558	3,955

In 1999, the Company sold several non-core properties for cash proceeds of $3,962,000. The carrying value of oil and gas properties was reduced by $5,094,000, including the associated accumulated site restoration liability which was reduced by $1,132,000 for the year.

In 2000, the Company capitalized indirect general and administrative costs of $472,000 (1999 - $584,000) relating to exploration and development activity.

On July 31, 1998 the Company entered into a flow-through share agreement raising $3,150,000. Under the applicable regulations the Company was required to spend all the $3,150,000 on qualifying Canadian exploration expenditures by December 31, 1999. $1,128,000 was spent by the end of 1998 and the remaining $2,022,000 was spent under the applicable look-back rules in 1999. The $3,150,000 in qualifying Canadian exploration expenditures are excluded from the Company's tax pools since they are renounced through to the investors in the flow-through shares.

In 2000 the Company calculated its year end ceiling test using the fourth quarter average oil price of $43.92. No ceiling test writedown was required as a result of this test in 2000 or 1999.

At year end, the estimated total future site restoration costs outstanding were $7,013,000 with an associated estimated salvage value of $3,524,000. A liability of $3,350,000 has been recognized to date for these future site restoration costs.

5. LONG-TERM DEBT

AS AT DECEMBER 31, 2000 AND 1999	2000 $	1999 $
Credit facility	**27,150**	22,254
Senior subordinate debenture	**-**	3,000
Mortgage	**50**	88
	27,200	25,342
Less current portion of long-term debt	**-**	(3,000)
Long-term debt	**27,200**	22,342

CREDIT FACILITIES

The Company has a $32,000,000 (1999 - $28,000,000) revolving demand credit facility which can be drawn in the form of loans or bankers' acceptances. As at December 31, 2000 the Company had drawn $27,150,000 (1999 - $22,254,000) from the credit facility consisting of a $5,150,000 demand loan and $22,000,000 in bankers' acceptances. The demand loan interest is paid monthly in arrears at the bank's pricing grid rate, which is dependent on the Company's most recent quarterly annualized debt and working capital deficit to cash flow ratio. The bankers' acceptance interest is paid in advance and bears interest at the bank's prime acceptance fee rate with a stamp fee which is also subject to the bank's pricing grid rate. At year end, the demand loan had a rate of prime and the banker's acceptance had a stamp fee of one percent plus the banker's acceptance fee rate.

The credit facility is reviewed annually by the bank and provided certain covenants are met, no principal repayments will be required in the next twelve months.

There is an additional demand credit facility in the amount of $2,000,000 (1999 - $2,000,000) to be used for acquisition and/or development drilling. This facility bears interest at the bank's prime lending rate plus 0.75 percent per annum. As at February 16, 2001, the Company has not drawn against this facility. Any funds drawn against the $2,000,000 demand credit facility create a monthly principal repayment over the half-life of the reserves being financed.

Collateral pledged for the credit facilities is comprised of the following:

a) A $50,000,000 fixed and floating charge demand debenture over the Company's oil and gas properties;

b) General assignment of book debts.

Senior subordinated debenture

The $3,000,000 debenture was fully repaid on November 1, 2000. The debenture required quarterly interest payments at a rate of 11.265% per annum.

6. CAPITAL STOCK

Authorized unlimited number of common shares

Issued and outstanding

AS AT DECEMBER 31, 2000 AND 1999	Number of Shares	Amount $
Balance - December 31, 1998	**17,638,834**	56,104
Options exercised	**9,000**	15
Flow-through shares issued	**110,100**	347
Shares purchased and cancelled under normal course issuer bid	**(21,700)**	(34)
Former employee shares cancelled	**(5,613)**	(13)
Tax effect of flow-through shares	**-**	(902)
Reduction of stated capital	**-**	(45,113)
Balance - December 31, 1999	**17,730,621**	10,404
Options exercised	**67,000**	114
Shares purchased and cancelled under normal course issuer bid	**(600,175)**	(342)
Former employee shares cancelled	**(1,606)**	(4)
Share issue costs	**-**	(9)
Tax effect of issue costs	**-**	4
Balance - December 31, 2000	**17,195,840**	10,167

On May 19, 1999, the Company's shareholders passed a resolution to reduce the stated capital of the Company's common shares by an amount of $45,113,181, being the Company's deficit as originally reported as at December 31, 1998, with the stated purpose of reducing the deficit to nil.

Pursuant to a normal course issuer bid throughout the year, the Company purchased 600,175 of its outstanding shares at an average cost of $2.36 per share. The total cost of acquiring these shares was $1,416,000 of which $1,074,000 exceeded the average carrying value and was charged to retained earnings.

STOCK OPTION PLANS

Under the original and the 1996 plans, the Company may grant up to 1,752,713 shares to its employees for the year ending 2000. Under both plans, the exercise price of each option equals the market price of the Company's stock on the date of the grant. The stock options vest over a three-year period from the date of grant with maximum terms ranging from 5 to 8 years.

A summary of the status of the Company's stock option plans as of December 31, 1999 and 2000, and changes during the years ending on those dates is presented below:

AS AT DECEMBER 31, 2000 AND 1999	2000		1999	
Fixed Options	Shares (000)	Weighted-Average Exercise Price	Shares (000)	Weighted-Average Exercise Price
Outstanding at beginning of year	1,712	$2.96	1,405	$2.77
Granted	-	-	755	$2.39
Exercised	(67)	$1.70	(9)	$1.70
Forfeited (Cancelled)	(17)	$3.47	(439)	$1.49
Outstanding at end of year	1,628	$3.00	1,712	$2.96
Options exercisable at year-end	1,615		978	

The following table summarizes information about fixed stock options outstanding at December 31, 2000.

AS AT DECEMBER 31, 2000					
	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at Dec. 31, 2000	Weighted-Average Remaining Contractual Life (years)	Number Weighted-Average Exercise Price	Exercisable at Dec. 31, 2000	Weighted-Average Exercise Price
$1.00 to $1.99	296,900	2.6 years	$ 1.58	296,900	$ 1.58
$2.00 to $2.99	899,000	3.0	$ 2.38	899,000	$ 2.38
$3.00 to $4.99	244,600	4.6	$ 4.23	231,266	$ 4.25
$5.00 to $8.99	125,000	3.2	$ 5.05	125,000	$ 5.05
$9.00 to $9.99	63,000	4.0	$ 9.75	63,000	$ 9.75
Total	1,628,500	3.2	$ 3.00	1,615,166	$ 3.00

In 1999, 401,000 options granted in 1991 were allowed to expire in consideration for the Company agreeing to pay the holders $360,900, being the difference between the fair market price and the option price.

Effective November 18, 1998 the Board of Directors implemented a Shareholder Rights Protection Plan ("the plan") which was approved at the annual and special meeting of shareholders on May 19, 1999. The plan defines the terms of a Permitted Bid in the event of a take-over offer for the Company and among other conditions requires that no shares be taken up under the Bid for a minimum of 45 days and a minimum level of shares being tendered. The plan is intended to provide the board of directors with adequate time to maximize shareholder value and to protect Upton shareholders from unfair, abusive or coersive take-over strategies.

7. INCOME TAXES

The provision for future income taxes reflects an effective tax rate that differs from the expected Canadian income tax rate. The differences are as follows:

AS AT DECEMBER 31, 2000 AND 1999	2000 $	1999 $
Expected combined Canadian federal and provincial income tax rate	**45.6%**	45.6%
Expected provision for income taxes	**8,261**	2,377
Increase (decrease) resulting from:		
Royalties and production taxes paid to the Crown	**3,696**	2,394
Resource allowance on Canadian production income	**(4,832)**	(2,285)
Recognition of U.S. future tax benefits in current year	**(1,350)**	-
Previously unrecognized U.S. losses	**(280)**	-
Future tax benefit of U.S. losses not recognized	**-**	11
Capital taxes	**2,248**	1,188
Other	**(553)**	116
Provision for income taxes	**7,190**	3,801

The future income tax benefit is composed of temporary differences and future income tax reductions. The following table shows the tax-affected amounts of those items with a tax value in excess of their net book value:

AS AT DECEMBER 31, 2000 AND 1999	2000 $	1999 $
Share issue costs	**251**	477
Tax value of property and equipment in excess of net book value	**5,951**	10,965
Future site restoration deductions	**1,146**	876
Other further deductions	**56**	25
Future income tax benefit	**7,404**	12,343

At December 31, the following deductions were available to claim against future taxable income:

AS AT DECEMBER 31, 2000 AND 1999	2000 $	1999 $
Canadian exploration expense	**4,774**	12,213
Canadian development expense	**20,695**	17,867
Canadian oil and gas property expense	**24,629**	25,521
Undepreciated capital cost	**14,142**	11,024
Total Canadian tax pools	**64,240**	66,625

In addition, the Company has costs and losses of U.S. $14,423,000 (1999 - U.S. $11,208,000) which may be claimed against future income in the United States. At December 31, 2000, on an after-tax basis, the tax value of the U.S. assets exceed the net book value by U.S. $3,043,000. Of this amount, U.S. $900,000 (Cdn. $1,350,000) is recorded as a future tax benefit. Based on management's best estimate, this is the amount estimated as more likely than not to be realized in the near future. A future tax asset has not been recognized for the remaining U.S. $2,142,000.

8. RELATED PARTY TRANSACTIONS

At December 31, the Company has the following transactions and balances with companies controlled by certain directors and officers of the Company:

AS AT DECEMBER 31, 2000 AND 1999	2000 $	1999 $
Accounts receivable	3	11
Accounts payable	-	90

The Company operates oil wells for companies in which certain directors have ownership interests. These transactions were made under normal business terms and conditions and at the same rates as with non-related parties.

Included in accounts receivable are two sets of non-interest bearing loans which have been offered to employees and officers for the purpose of acquiring shares in the Company. At December 31, 2000, the Company had non-interest bearing loans due from its officers of $182,554 (1999 - $105,750) and employees of $262,690 (1999 - $203,543). The loans were used to purchase shares and are secured by an assignment of these shares that are held in escrow until the loans are repaid. From the first set of interest free loans offered in 1998, $302,813 is outstanding which becomes due December 31, 2001. The second set of non-interest bearing loans offered on March 1, 2000 have $142,431 outstanding which is to be repaid through three equal payments over the next three years on the anniversary date of the loans.

9. SEGMENTED INFORMATION BY GEOGRAPHIC SEGMENT

AS AT DECEMBER 31, 2000 AND 1999	Canada $	United States $	Consolidated $
Year ended December 31, 2000			
Revenues	53,547	3,069	56,616
Earnings before taxes	17,466	649	18,115
Net capital expenditures	23,696	5,851	29,547
Identifiable assets	68,024	13,329	81,353
Year ended December 31, 1999			
Revenues	30,182	957	31,139
Earnings (loss) before taxes	5,236	(24)	5,212
Net capital expenditures	10,327	732	11,059
Identifiable assets	61,323	6,206	67,529

10. PER SHARE INFORMATION

AS AT DECEMBER 31, 2000 AND 1999	2000 $	1999 $
Basic earnings per common share	**0.63**	0.08
Fully diluted earnings per common share	**0.58**	anti-dilutive
Basic cash flow from operations per common share	**1.67**	0.65
Fully diluted cash flow from operations per common share	**1.54**	0.62
Weighted average number of basic common shares outstanding	**17,448,006**	17,670,409
Weighted average number fully diluted common shares outstanding	**19,122,519**	19,143,722

11. FINANCIAL INSTRUMENTS AND HEDGING ACTIVITY

The Company's financial instruments recognized in the financial statements consist of accounts receivable, accounts payable and long-term debt. The fair value of the accounts receivable and payable approximate their carrying amounts due to the short-term maturity of these instruments, while the par value of the long-term debt credit facility approximates its carrying amount as the interest rate is a floating market rate.

The Company utilizes certain derivative financial instruments including crude oil swap contracts, crude oil option contracts, foreign exchange swap contracts and foreign exchange option contracts. The Company enters into these contracts to manage its cash flow exposure to the volatility of crude oil prices and foreign exchange rates. Financial derivative contracts outstanding at December 31, 2000 were as follows:

CRUDE OIL SWAPS

Term	Quantity/Day	Price/Barrel
January 1, 2001 to March 31, 2001	500 barrels	U.S. $25.77 WTI
January 1, 2001 to March 31, 2001	500 barrels	U.S. $26.55 WTI
April 1, 2001 to June 30, 2001	500 barrels	U.S. $25.45 WTI

CRUDE OIL OPTIONS (COLLAR)

Term	Quantity/Day	Price/Barrel
January 1, 2001 to December 31, 2001	500 barrels	Call U.S. $29.68 WTI Put U.S. $26.00 WTI
January 1, 2001 to December 31, 2001	500 barrels	Call U.S. $30.69 WTI Put U.S. $28.00 WTI

The fair value of these swaps and collar based on quotes provided by brokers would result in a gain of $816,845 U.S. if terminated at December 31, 2000.

FOREIGN EXCHANGE SWAP

Effective December 20, 2000 and expiring December 27, 2001, the Company bought an average rate put of $6,000,000 U.S. for the year for $0.66116 U.S. Effective December 20, 2000 and expiring Jan 31, 2002, the company sold a call option of $6,000,000 for the year for $0.64935 U.S. The fair value of these contracts at December 31, 2000 is a gain of approximately $44,976.

12. SUBSEQUENT EVENT

On March 20, 2001, the Company disposed of non-core properties for proceeds of $7.2 million before adjustments.

SUPPLEMENTARY INFORMATION

QUARTERLY FINANCIAL INFORMATION

($thousands except per share amounts)	2000					1999				
	1Q	**2Q**	**3Q**	**4Q**	**Total**	1Q	2Q	3Q	4Q	Total
Revenues	**13,727**	**12,209**	**14,815**	**15,865**	**56,616**	5,218	5,225	8,331	12,366	31,139
Earnings (loss)	**2,622**	**1,904**	**3,098**	**3,301**	**10,925**	(308)*	(360)*	338*	1,741	1,411
Earnings (loss) per share ($)	**0.15**	**0.11**	**0.18**	**0.19**	**0.63**	(0.02)*	(0.02)*	0.02*	0.10	0.08
Cash flow from operations	**7,388**	**5,658**	**7,731**	**8,325**	**29,100**	1,250	1,012	2,865	6,363	11,490
Cash flow from operations/share ($)	**0.42**	**0.33**	**0.44**	**0.48**	**1.67**	0.07	0.06	0.16	0.36	0.65

* Restated in accordance with the new accounting for income tax standard set by the Canadian Institute of Chartered Accountants

TRADING RANGE OF COMMON SHARES

	2000					1999				
	1Q	**2Q**	**3Q**	**4Q**	**Total**	1Q	2Q	3Q	4Q	Total
High ($/share)	**2.80**	**3.20**	**3.25**	**3.30**		2.25	2.85	3.20	2.75	
Low ($/share)	**2.05**	**2.10**	**2.41**	**2.34**		1.20	1.81	2.40	2.00	
Close ($/share)	**2.25**	**2.82**	**3.15**	**2.61**		2.00	2.45	2.99	2.30	
Volume (thousands)	**2,606**	**1,091**	**1,888**	**1,446**	**7,031**	856	1,012	626	1,275	3,769

FIVE-YEAR SUMMARY

($ thousands, except as otherwise noted)	2000	1999	1998	1997	1996
FINANCIAL					
Revenues					
Crude oil revenue	**56,616**	31,139	29,713	42,826	33,797
Less: royalties	**(14,242)**	(8,172)	(6,157)	(8,216)	(7,678)
Revenue net of royalties	**42,374**	22,967	23,556	34,610	26,119
Expenses					
Operating	**5,926**	5,428	5,959	6,472	3,549
Interest	**2,166**	1,991	1,718	1,236	990
General and administrative	**2,934**	2,870	2,347	2,313	1,883
Depletion and depreciation	**12,401**	6,682	48,227	46,827	9,354
Site restoration	**832**	784	1,099	547	532
Cash flow from operations	**29,100**	11,490	12,418	22,920	18,206
Per share - basic	**1.67**	0.65	0.73	1.52	1.52
Per share - fully diluted	**1.54**	0.62	0.70	1.35	1.38
Net earnings (loss)	**10,925**	1,411	(23,143)*	(15,803)*	5,023
Per share - basic	**0.63**	0.08	(1.36)*	(1.05)*	0.42
Per share - fully diluted	**0.58**	anti-dilutive	anti-dilutive*	anti-dilutive*	0.38
Balance sheet information					
Net capital expenditures	**29,547**	11,059	20,444	66,865	27,516
Long-term debt	**27,200**	22,342	26,135	16,595	15,893
Working capital deficit	**2,919**	5,974	1,795	6,214	4,914
Total assets	**81,353**	67,529	63,927*	82,763*	59,941
Shareholders' equity	**38,275**	28,661	27,837*	48,508*	22,985
Common share information					
Shares outstanding at year end (thousands)					
- basic	**17,196**	17,731	17,639	16,607	12,181
- fully diluted	**18,824**	19,443	19,044	18,172	13,302
Weighted average common shares (thousands)					
- basic	17,448	17,670	17,028	15,055	12,016
- fully diluted	19,123	19,144	18,206	17,082	13,172
Equity market capitalization (Dec 31, $mm)	44.8	40.8	37.0	70.6	96.2
OPERATING					
Reserves (thousands of barrels)					
Proven	**8,865**	8,920	10,019	6,709	5,797
Probable	**3,986**	4,023	3,793	1,215	950
Total	**12,851**	12,943	13,812	7,924	6,747
Established	**10,858**	10,931	11,916	7,317	6,272
Production and netbacks					
Average barrels per day	**4,263**	3,522	4,441	4,852	3,594
Exit rate (December average - bopd)	**4,933**	4,578	3,731	5,251	3,983
Total barrels (thousands)	**1,560**	1,285	1,621	1,771	1,316
Net realized crude oil price ($ per barrel)	**36.28**	24.22	18.33	24.18	25.69
Operating costs ($ per barrel)	**3.80**	4.22	3.68	3.65	2.70
Operating netback ($ per barrel)	**23.35**	13.64	10.85	15.89	17.16
All-in cash netback ($ per barrel)	**18.64**	8.94	7.66	12.94	13.84
Land holdings					
Total land (thousands of net acres)	**175**	189	215	189	122
Undeveloped land (thousands of net acres)	**151**	166	195	168	92
Drilling activity					
Gross	**46.0**	24.0	26.0	77.0	49.0
Net	**35.6**	22.0	19.9	48.5	31.8
Number of employees					
Head office	**25**	25	26	32	21
Field office	**14**	13	12	11	13

* Restated in accordance with the new accounting for income tax standard set by the Canadian Institute of Chartered Accountants.

CORPORATE INFORMATION

DIRECTORS

William R. Dutton [5]
Chairman of the Board
Upton Resources Inc.
Calgary, Alberta

G. Scott Dutton [3][5]
President and Chief Executive Officer
Upton Resources Inc.
Calgary, Alberta

Anthony H. Bogert [2][4][5]
Vice President
BMO Nesbitt Burns
Ottawa, Ontario

D. Grant Devine [1][3][4][5]
President
Grant Devine Management Incorporated
Regina, Saskatchewan

W. Craig Dutton [1][4][5]
Chief Operating Officer
Jades Securities Inc.
Humboldt, Saskatchewan

Garry H. Huntington [1][2][5]
Senior Vice President
Danka Business Systems PLC
Regina, Saskatchewan

Paul J. Schoenhals [2][3][5]
President
Petroleum Industry Training Institute
Calgary, Alberta

J. Ronald Woods [1][5]
President
Rowood Capital Corp
Toronto, Ontario

OFFICERS

G. Scott Dutton
President and Chief Executive Officer

Philip H. Grubbe
Vice President, Finance and Chief Financial Officer

Gregory D. Henders
Vice President, Operations

Robin D. Irwin
Vice President, Land

Andre St. Onge
Vice President, Exploration

C. Steven Cohen
Corporate Secretary

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Calgary, Alberta

FINANCIAL INSTITUTION

National Bank of Canada
Calgary, Alberta

LEGAL COUNSEL

Burnet, Duckworth & Palmer
Calgary, Alberta

TRANSFER AGENT AND REGISTRAR

The CIBC Mellon Trust Company
Toronto, Calgary and Vancouver

Upton's Team Exploration:

Julie Barnden
George Hassler
Darrol Proskow
Liz McLeod
Eric Strachan

Finance:

Kim Adair
Pennie Barry
Darren Dittmer
Dean Kaiser
Shawna Venables

Land:

Darcy Biever
Wendy Bursey
Laury Chapman
Nora Rennie
Elizabeth Urquhart
Margaret Wyonzek

Operations:

Mark Bilozir
Karen Pagano
Heather Spencer
Darlene Ward

Estevan Field Office:

Dave Bayerle
Stacy Butz
Brad Clow
Alan Dixon
Kristin Dupuis
Brad Dutton
Kim Harbourne
Jim Larter
Lynn Mack
Tammi Mann
Dean Martens
Doug Moberg
Greg Swallow
Vic Young

[1] Member of Audit Committee	[4] Member of Health, Safety and Environmental Committee
[2] Member of Compensation Committee	[5] Member of Reserves Committee
[3] Member of Corporate Governance Committee	

ANNUAL AND SPECIAL MEETING

The Annual and Special Meeting of the shareholders of Upton Resources Inc. will be held on May 16, 2001 at 11:00 a.m. in the Wildrose C room of the Sheraton Suites Calgary Eau Claire, 255 Barclay Parade S.W., Calgary, Alberta.

Shareholders are encouraged to attend. Those unable to do so should complete the form of proxy and forward to CIBC Mellon Trust Company at least 48 hours prior to the meeting.

STOCK EXCHANGE LISTING

Upton's common shares trade on The Toronto Stock Exchange under the symbol "URC".

Designed and Produced by Merlin Creative Group Inc.

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